Enclosure 3

Turkey Point Nuclear Plant Units 3 and 4

Subsequent License Renewal Application

Revision 1

(Public Version)

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Withheld from Public Disclosure Under 10 CFR 2.390

Florida Power & Light Company
Turkey Point Nuclear Plant Units 3 and 4
Subsequent License Renewal Application

April 2018

Revision 1

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1.0 ADMINISTRATIVE INFORMATION

Pursuant to Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), *Requirements for Renewal of Operating Licenses for Nuclear Power Plants* (Reference 1.6.3), this subsequent license renewal application (SLRA) seeks renewal for an additional 20-year term of the facility operating licenses for Turkey Point Nuclear Generating Unit 3 (DPR-31) and Unit 4 (DPR-41). The Unit 3 operating license (DPR-31) currently expires at midnight, July 19, 2032. The Unit 4 operating license (DPR-41) currently expires at midnight, April 10, 2033. The SLRA includes renewal of the source, special nuclear, and byproduct materials licenses that are combined in the Unit 3 and Unit 4 licenses.

The SLRA is based on the guidance provided by the Nuclear Regulatory Commission (NRC) in NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants* (SRP-SLR) (Reference 1.6.4), and the guidance provided by Nuclear Energy Institute (NEI) 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal* (Reference 1.6.7).

The SLRA is intended to provide sufficient information for the NRC to complete its technical and environmental reviews pursuant to 10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants* (Reference 1.6.3), and 10 CFR Part 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions* (Reference 1.6.2). The SLRA is provided to meet the standards required by 10 CFR 54.29 in support of the issuance of the subsequent renewed operating licenses for Turkey Point Nuclear Generating Units 3 and 4 (also referred to as PTN).

1.1 GENERAL INFORMATION

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

1.1.1 Name of Applicant

The Florida Power & Light Company (FPL) hereby applies for subsequent renewed operating licenses for Turkey Point Nuclear Generating Units 3 and 4.

1.1.2 Address of Applicant

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Address of the Turkey Point Nuclear Generating Unit:

Florida Power & Light Company
Turkey Point Nuclear Generating Unit
9760 SW 344th Street
Florida City, FL 33035-1800

1.1.3 Descriptions of Business or Occupation of Applicant

FPL is an investor-owned utility, primarily engaged in the generation, transmission, and distribution of electricity. FPL supplies electric service to approximately 10 million people through approximately 4.9 million customer accounts. The service territory covers almost the entire eastern seaboard and lower west coast of the State of Florida. To service this area, FPL operates 45 electric generating facilities with an installed capacity of 26,836 megawatts electric (MWe), including the Turkey Point Nuclear Generating Units.

The current Turkey Point Nuclear Generating Units operating licenses will expire as follows:

- At midnight on July 19, 2032, for Turkey Point Nuclear Generating Unit 3 (Renewed Facility Operating License No. DPR-31)
- At midnight on April 10, 2033, for Turkey Point Nuclear Generating Unit 4 (Renewed Facility Operating License No. DPR-41)

FPL will continue as the licensed operator on the subsequent renewed operating licenses.

1.1.4 Organization and Management of Applicant

FPL is a public utility incorporated under the laws of the State of Florida, with its principal office located in Juno Beach, Florida.

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

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

Names and Addresses of the Board of Directors		
Name	**Title**	**Address**
James L. Robo	Director	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
John W. Ketchum	Director	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
Eric E. Silagy	Director	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420

Names and Addresses of Principal Officers		
Name	**Title**	**Address**
James L. Robo	Chairman of the Board	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
Eric E. Silagy	President and Chief Executive Officer	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
John W. Ketchum	Executive Vice President, Finance and Chief Financial Officer	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
Manoochehr K. Nazar	President, Nuclear Division and Chief Nuclear Officer	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
Miguel Arechabala	Executive Vice President, Power Generation Division	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
Deborah H. Caplan	Executive Vice President, Human Resources and Corporate Services	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420

Names and Addresses of Principal Officers (Continued)		
Name	**Title**	**Address**
Mark E. Hickson	Executive Vice President Corporate Development, Strategy, Quality and Integration	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
Charles E. Sieving	Executive Vice President and General Counsel	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420
William L. Yeager	Executive Vice President, Engineering, Construction and Integrated Supply Chain	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, FL 33408-0420

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

FPL requests subsequent renewal of the operating licenses issued under Section 104b of the Atomic Energy Act of 1954, as amended, for Turkey Point Nuclear Generating Unit 3 and Unit 4 (License Nos. DPR-31 and DPR-41, respectively), for a period of 20 years beyond the expiration of the current renewed operating licenses. This would extend the renewed operating license for Turkey Point Nuclear Generating Unit 3 from midnight on July 19, 2032, to midnight July 19, 2052, and Turkey Point Nuclear Generating Unit 4 renewed operating license from midnight on April 10, 2033, to midnight on April 10, 2053. This SLRA includes a request for renewal of those NRC source material, special nuclear material, and by-product material licenses that are subsumed into or combined with the current renewed operating licenses.

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

1.1.6 Earliest and Latest Dates for Alterations

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

1.1.7 Regulatory Agencies with Jurisdiction

Regulatory agencies with jurisdiction over the Turkey Point Nuclear Generating Unit revenue are:

United States Securities and Exchange Commission
100 F Street NE
Washington, D.C. 20549

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

Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399

1.1.8 Local News Publications

News publications that circulate in the area surrounding the Turkey Point Nuclear Generating Unit and are considered appropriate to give reasonable notice of this SLRA to those municipalities, private utilities, public bodies and cooperatives that might have a potential interest in the facility, include the following:

Miami Herald
3511 NW 91 Ave.
Doral, FL 33172

El Nuevo Herald
3511 NW 91 Ave.
Doral, FL 33172

South Dade News Leader
205 N Flagler Ave.
Homestead, FL 33030

Sun-Sentinel
333 SW 12th Avenue
Deerfield Beach, FL 33442

Palm Beach Post
2751 South Dixie Highway
West Palm Beach, FL 33405

1.1.9 Conforming Changes to Standard Indemnity Agreement

The requirements of 10 CFR 54.19(b) state that SLRAs must include, "…conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The current indemnity agreement (B-46) for the Turkey Point Nuclear Generating Unit states, in Article VII, that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement, which is the last to expire. Item 3 of the Attachment to the indemnity agreement, as revised by Amendment No. 5, lists four license numbers. FPL has reviewed the original Indemnity Agreement and the Amendments. Neither Article VII nor Item 3 of the Attachment specifies an expiration date for license numbers DPR-31 or DPR-41. Therefore, no changes to the Indemnity Agreement are deemed necessary as part of this SLRA. Should the license numbers be changed upon issuance of the subsequent renewed licenses, FPL requests that conforming changes be made to Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate.

1.1.10 Restricted Data Agreement

This SLRA does not contain restricted data or other national defense information, and the applicant does not expect that any activity under the subsequent renewed operating licenses for the Turkey Point Nuclear Generating Unit will involve such information. However, pursuant to 10 CFR 54.17(f) and (g), and 10 CFR 50.37, the applicant agrees that it will not permit any individual to have access to, or any facility to possess, restricted data or classified national security information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Part 25, *Access Authorization,* and/or 10 CFR Part 95, *Facility Security Clearance and Safeguarding of National Security Information and Restricted Data.*

1.2 PLANT DESCRIPTION

The Turkey Point site includes five units. Units 1 and 2 were formerly operated as natural-gas/oil steam-generating units. However, Units 1 and 2 have been repurposed in the synchronous condenser mode to support transmission reliability and will be maintained in this condition through the subsequent period of extended operation (SPEO). The Units 1 and 2 generators remain on site to help stabilize and optimize grid performance, but do not generate power or process water. Units 3 and 4 are the nuclear pressurized water reactors (PWRs) that are the subject of this report. Unit 5 is a natural-gas combined-cycle steam-generating unit.

Each of the two nuclear units employs a pressurized water nuclear steam supply system (NSSS) with three coolant loops furnished by the Westinghouse Electric Corporation. Each reactor is designed to produce a core thermal power output of 2644 megawatts-thermal (MWt) with a corresponding gross electrical output of approximately 913 (Unit 3) and 923 (Unit 4) MWe. Onsite electrical power usage amounts to slightly more than 100 MWe, leaving Units 3 and 4 with a reliable net summer rating of 811 and 821 MWe, respectively, or a combined Turkey Point Nuclear Generating Unit output of 1,632 MWe. Commercial operation for Unit 3 began on July 19, 1972, and for Unit 4 on April 10, 1973.

The major structures are two containments, one auxiliary building, one turbine building and one control building. Each containment is a right-vertical, post-tensioned, reinforced-concrete cylinder with prestressed tendons in the vertical wall, a reinforced and post-tensioned concrete hemispherical domed roof and a substantial base slab of reinforced concrete.

1.3 APPLICATION STRUCTURE

This SLRA is structured in accordance with NEI 17-01. The SLRA is structured to address the guidance provided in NUREG-2192 (SRP-SLR). 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 aging management programs (AMPs) and to identify existing programs that will be augmented for SLR. The results of the aging management review (AMR), using NUREG-2191, have been documented and are illustrated in table format in Section 3, Aging Management Review Results, of this SLRA.

Turkey Point Nuclear Generating Units 3 and 4 are constructed of similar materials with similar environments. Unless otherwise noted throughout this SLRA, plant systems and structures discussed in this SLRA apply to both units.

The SLRA is divided into the following sections:

- Section 1 – Administrative Information

  This section provides the administrative information required by 10 CFR 54.17 and 10 CFR 54.19. It describes the plant and states the purpose for this SLRA. Included in this section are the names, addresses, business descriptions, as well as other administrative information. This section also provides an overview of the structure of the SLRA, and a listing of acronyms (Section 1.7) and general references (Section 1.6) used throughout the SLRA.

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

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

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

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

Selected components, such as equipment supports, structural items (e.g., penetration seals, structural bolting and insulation), and passive electrical components, were more effectively scoped and screened as commodities. Under the commodity approach, these component groups were evaluated based upon common environments and materials. Commodities requiring an AMR are presented in Sections 2.4 and 2.5. Component intended functions and reference to the applicable Section 3 table are provided.

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

- Section 3 – Aging Management Review Results

  10 CFR 54.21(a)(3) requires a demonstration that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the SPEO. Section 3 presents the results of the AMRs. Section 3 is the link between the scoping and screening results provided in Section 2 and the AMPs provided in Appendix B.

  AMR results are presented in tabular form, in a format in accordance with NUREG-2192. For mechanical systems, AMR results are provided in Sections 3.1 through 3.4 for the reactor coolant system (RCS), engineered safety features (ESFs), auxiliary systems, and steam and power conversion systems, respectively. AMR results for structures and component supports are provided in Section 3.5. AMR results for electrical commodities are provided in Section 3.6.

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

- Section 4 – Time-Limited Aging Analyses

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

- 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 SPEO. A summary description of the evaluation of TLAAs for the SPEO is also included. Following issuance of the renewed licenses, the material contained in this appendix will be incorporated into the UFSAR.

- Appendix B – Aging Management Programs

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

  Sections B.2.2 and B.2.3 discuss those programs that are contained in Chapter X and Chapter XI of NUREG-2191, respectively. A description of the AMP is provided and a conclusion based upon the results of an evaluation against each of the 10 elements provided in NUREG-2191 is drawn. In some cases, exceptions and justifications for managing aging are provided for specific NUREG-2191 elements. Additionally, operating experience (OE) related to the AMP is provided.

- Appendix C – Appendix C MRP-227-A Gap Analysis

  This appendix provides the gap analysis for SLR when compared to the current PTN Reactor Vessel Internals Program based on the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP)-227-A.

- Appendix D – Technical Specification Changes

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

- Appendix E – Applicant's Environmental Report—Subsequent Operating License Renewal Stage

  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 Turkey Point Nuclear Generating Units 3 and 4.

1.4 CURRENT LICENSING BASIS CHANGES DURING NRC REVIEW

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

In accordance with 10 CFR 54.21(d), the Turkey Point Nuclear Generating Unit will maintain (1) a summary description of programs and activities in the UFSAR for managing the effects of aging and (2) summaries of the TLAA evaluations.

1.5 CONTACT INFORMATION

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

Mr. William Maher
Senior Director – Nuclear
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

E-mail: William.Maher@fpl.com

1.6 GENERAL REFERENCES

1.6.1 10 CFR Part 50, Domestic Licensing of Production and Utilization Facilities.

1.6.2 10 CFR Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions.

1.6.3 10 CFR Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants.

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

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

1.6.6 Regulatory Guide 1.188, Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses, Revision 1, September 2005.

1.6.7 NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal Rule, March 2017.

1.6.8 10 CFR 50.48, Fire Protection.

1.6.9 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.

1.6.10 10 CFR 50.61, Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events.

1.6.11 10 CFR 50.62, Requirements for Reduction of Risk from Anticipated Transients without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants.

1.6.12 10 CFR 50.63, Loss of All Alternating Current Power.

1.6.13 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.

1.6.14 10 CFR Part 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.

1.6.15 10 CFR Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions.

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

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

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

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

1.6.20 EPRI Materials Reliability Program (MRP) Report 1016596, Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-Rev. 0), Revision 0, December 2008.

1.6.21 EPRI MRP Report 1022863, Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A-Rev. 0), Revision 0, December 2011.

1.7 ABBREVIATIONS AND ACRONYMS

<u>Abbreviation or Acronym</u>	<u>Description</u>
¼T	one quarter of the vessel wall thickness from the clad/base metal interface
¾T	three quarters of the vessel wall thickness from the clad/base metal interface
3-D	three dimensional
ΔRT_{NDT}	shift in the initial RT_{NDT}
a/l	aspect ratio
AAC	Aluminum Conductor
AB	auxiliary building
AC (ac)	alternating current
ACE	Apparent Cause Evaluation
ACI	American Concrete Institute
ACSR	aluminum conductor steel reinforced
ADAMS	Agencywide Documents Access and Management System
AERM	aging effect requiring management
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
ALARA	As-Low-As-Reasonably-Achievable
ALE	adverse localized environment
AMP	Aging Management Program
AMR	Aging Management Review
AMSAC	ATWS Mitigating System Actuation Circuitry
ANSI	American National Standards Institute
API	American Petroleum Institute
AR	action request
ART	adjusted reference temperature
ASME	American Society of Mechanical Engineers

Abbreviation or Acronym	**Description**
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ASR	alkali silicate reactions
AST	Alternate Source Term
ASTM	American Society for Testing Materials
ATWS	anticipated transient without scram
AVB	anti-vibration bar
B&W	Babcock & Wilcox
B&WOG	Babcock & Wilcox Owners Group
BACC	Boric Acid Corrosion Control
BEBs	baffle-edge bolts
BFBs	baffle-former bolts
BMI	bottom-mounted instrumentation
BMN	bottom mounted nozzle
BMIFTT	bottom-mounted instrumentation flux thimble tubing
BOP	balance-of-plant
BTP	Branch Technical Position
BWR	boiling water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CAP	Corrective Action Program
CAPR	Corrective Action to Prevent Recurrence
CASS	cast austenitic stainless steel
CCW	component cooling water
CE	Combustion Engineering
CET	core exit thermocouple
CETNA	core exit thermocouple nozzle adapter
CF	cubic feet
CFR	Code of Federal Regulations

Abbreviation or Acronym	Description
CLB	Current Licensing Basis
CR	control room; Condition Report
CRD	control rod drive
CRDM	control rod drive mechanism
CRDMCS	control rod drive mechanism cooling system
CREVS	control room emergency ventilation system
CRGT	control rod guide tube assembly
CRVS	control room ventilation system
CS	containment spray
CSI	component support and inspections
CSS	containment spray system
CSTs	condensate storage tanks
CTWS	closed treated water systems
CUF	cumulative usage factor
CUF_{en}	environmentally adjusted cumulative usage factor
CVCS	chemical and volume control system
CW	cold worked
DBA	design basis accident
DBDs	Design Basis Documents
DBE	design basis event
dc	direct current
DFIs	Deficiency Follow-Up Inspections
DG	Draft Regulatory Guide
DO	dissolved oxygen
Doc Pac	Documentation Package
DOR	Division of Operating Reactors
DOST	diesel oil storage tank
dpa	displacements per atom
DWST	demineralized water storage tank

Abbreviation or Acronym	Description
EAF	environmentally assisted fatigue
EB	exclusion boundary
EC	eddy current; engineering change
ECC	emergency containment cooling
ECCS	emergency core cooling system
EC/FAC	erosion corrosion/flow-accelerated corrosion
ECT	eddy current testing
EDG	emergency diesel generator
EFPY	effective full power years
EMA	equivalent margins analysis
EOC	end of cycle
EOCI	Electrical Overhead Crane Institute
EOL	end-of-life
EPDM	ethylene propylene diene monomers
EPR	ethylene propylene rubber
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate
EQ	Environmental Qualification
EQ Doc Pacs	Environmental Qualification Documentation Packages
ER	environmental report
ESF	engineered safety feature
ESMMC	External Surfaces Monitoring of Mechanical Components
ETSS	eddy current technique specification sheet
EVT-1	enhanced visual examination
FAC	flow-accelerated corrosion
FCG	fatigue crack growth
FCVs	feedwater control (or regulating) valves
FDB	flow distribution baffle

Abbreviation or Acronym	**Description**
Fe	iron
F_{en} values	environmental fatigue multipliers
FIV	flow induced vibration
FME	foreign material exclusion
FMECA	failure modes, effects, and criticality assessment
FOSAR	foreign object search and retrieval
FOST	fuel oil storage tank
FPI	fire protection impairment
FPL	Florida Power & Light
FPRA	fire probabilistic risk analysis
FPS	fire protection system
FSAR	Final Safety Analysis Report
ft-lb	foot-pound
FWLB	feedwater line break
GALL	Generic Aging Lessons Learned
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GDC	General Design Criteria
GL	Generic Letter
GSI	Generic Safety Issue
GTA	guide tube assembly
GTM	gas transfer membrane
GUTS	guaranteed ultimate tensile strength
H*	alternate repair criteria
HAZ	heat affected zone
HCF	high cycle fatigue
HDPE	high-density polyethylene
HELB	high energy line break

Abbreviation or Acronym	**Description**
HEPA	high-efficiency particulate air
HHSI	high head safety injection
HVAC	heating, ventilation and air conditioning
HX	heat exchanger
I&C	instrumentation and controls
I&E	inspection and evaluation
I/O	insurge/outsurge
IAS	instrument air system
IASCC	irradiation assisted stress corrosion cracking
ICW	intake cooling water
ID	inner diameter
IE	irradiation embrittlement; Inspection and Enforcement
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate tests
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IR	insulation resistance
IS	intermediate shell
ISG	Interim Staff Guidance
ISI	Inservice Inspection
ISI Program Plan	Interval-ISI-PTN-3/4-Program Plan
ISR/IC	irradiation-enhanced stress relaxation or creep
ksi	kilo-pounds per square inch
LAI	licensee action item
LAR	license amendment request
LBB	Leak-Before-Break

Abbreviation or Acronym	Description
LCF	low cycle fatigue
LCP	lower-core plate
LER	Licensee Event Reports
Li	lithium
LLRT	local leakage rate testing
LOCA	loss of coolant accident
LOOP	loss of offsite power
LPZ	low population zone
LRA	license renewal application
LRT	leak rate test
LS	lower shell
LTAM	long term asset management
LTCAs	long term corrective actions
LTOP	low temperature overpressure protection
LWR	light-water reactor
MEB	metal enclosed bus
MeV	million electron volts
MIC	microbiologically induced corrosion
MIRVP	Master Integrated Reactor Vessel Program
MPa	megapascals
MR	Maintenance Rule
MRP	Materials Reliability Program
MRV	minimum required value
MSIVs	main steam isolation valves
MSLB	main steam line break
MSR	moisture separator reheater
MW	megawatts
MWe	megawatts electric
MWt	megawatts thermal

Abbreviation or Acronym	**Description**
n/cm^2	neutrons/square centimeter
NAMS	Nuclear Asset Management Suite
NaTB	sodium tetraborate
NCCS	normal containment cooling system
NCR	nonconformance report
NCV	non-cited violation
NCVS	normal containment ventilation system
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NESC	National Electrical Safety Code
NIS	nuclear instrumentation system
NFPA	National Fire Protection Association
NNS	nonnuclear-safety related
NOP	normal operating loads
NOP-NOT	normal operating pressure and temperature
NPO	non-power operations
NPS	nominal pipe size
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSCA	nuclear safety capability assessment
NSS	Nitrogen and Hydrogen
NSSS	nuclear steam supply system
NUGEQ	Nuclear Utility Group on Equipment Qualification
NUMARC	Nuclear Management and Resources Council
OCCW	open-cycle cooling water
ODCM	Offsite Dose Calculation Manual
OE	operating experience
ORNL	Oak Ridge National Laboratory

Abbreviation or Acronym	**Description**
P&ID	piping and instrument diagram
P-T	pressure-temperature
PAOT	Post Accident Operability Time
PCR	procedure change request
PEO	period of extended operation
PF	prestressing force
PH	precipitation-hardened
PLL	predicted lower limit
PM	preventive maintenance
POD	prompt operability determination
PORV	power operated relief valve
PPE	personal protective equipment
ppm	parts per million
PRT	pressurizer relief tank
PTF	predicted tendon force
PTN	Turkey Point Nuclear Generating Units
PTS	pressurized thermal shock
PUL	predicted upper limit
PVC	polyvinyl chloride
PWM	primary water makeup
PWR	pressurized water reactor
PWROG	Pressurized Water Reactor Owners Group
PWSCC	primary water stress corrosion cracking
PWST	primary water storage tank
QA	Quality Assurance
QC	Quality Control
QHSA	quick hit self-assessment
QSPDS	Qualified Safety Parameter Display System

Abbreviation or Acronym	Description
RAI	request for additional information
RCB	reactor containment building
RCCAs	rod control cluster assemblies
RCDTs	reactor coolant drain tanks
RCL	reactor coolant loop
RCP	reactor coolant pump
RCS	reactor coolant system
RFO	refueling outage
RG	Regulatory Guide
RHR	residual heat removal
RHRS	RHR system
RIS	Regulatory Issue Summary
RPS	reactor protection system
RPS/ESFAS	reactor protection system/engineered safety features actuation system
RPV	reactor pressure vessel
RTD	resistance temperature detector
RT_{NDT}	nil-ductility reference temperature
$RT_{NDT(U)}$	unirradiated nil-ductility reference temperature
RT_{PTS}	pressurized thermal shock reference temperature (maximum nil-ductility reference temperature)
RV	reactor vessel
RVCH	reactor vessel closure head
RVI	reactor vessel internal
RVLMS	reactor vessel level monitoring system
RWST	refueling water storage tank
RWT	raw water tank
S/Gs	steam generators
SBO	station blackout

Abbreviation or Acronym	**Description**
SCs	structures and components
SCC	stress corrosion cracking
SE	Safety Evaluation
SEA	Seabrook Station
SEI/ASCE	Structural Engineering Institute/American Society of Civil Engineers Standard
SER	Safety Evaluation Report
SFP	spent fuel pool
SFPC	spent fuel pool cooling
SFPCS	SFP cooling system
SG	steam generator
SGBD	steam generator blowdown
SGFP	steam generator feed pump
SGFWP	steam generator feedwater pump
SGIP	Steam Generator Integrity Program
SGTR	steam generator tube rupture
SHR	shutdown heat removal
SI	safety injection
SIS	safety injection system
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SLRBD	subsequent license renewal boundary drawings
SO_2	sulfur dioxide
SPEO	subsequent period of extended operation
SPV	single point vulnerable
SR	safety-related; silicone rubber
SR/IC	irradiation induced stress relaxation/creep
SRP-SLR	Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (NUREG-2192)
SS	stainless steel

Abbreviation or Acronym	**Description**
SSA	safe shutdown analysis
SSCs	systems, structures, and components
SSE	safe shutdown earthquake
SSGF	standby steam generator feedwater
TE	thermal embrittlement
TLAA	time-limited aging analyses
TPCW	turbine plant cooling water
TR	Topical Report
TS	Technical Specifications
TSP	tube support plate
TT	thermally treated
TTS	top-of-tubesheet
UCP	upper-core plate
UFSAR	Updated Final Safety Analysis Report
UHS	ultimate heat sink
US	upper shell
USE	upper shelf energy
USIs	unresolved safety issues
UT	ultrasonic testing
VCTs	volume control tanks
VS	void swelling
VT-1	visual inspections
VUHP	vessel upper head penetration
WCAP	Westinghouse Commercial Atomic Power
WO	work order
WOG	Westinghouse Owners Group

Abbreviation or Acronym	Description
XLPE	cross-linked polyethylene

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

This section describes the methodology for identifying structures and components subject to aging management review (AMR) in the Turkey Point Nuclear Generating Unit (hereafter referred to as “Turkey Point”) subsequent license renewal (SLR) integrated plant assessment (IPA). For the systems, structures, or components (SSCs) within the scope of SLR, 10 CFR 54.21(a)(1) requires the SLR applicant to identify and list those structures and components subject to AMR. Furthermore, 10 CFR 54.21(a)(2) requires that the methods used to implement the requirements of 10 CFR 54.21(a)(1) be described and justified. Section 2 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 subsequent license renewal in accordance with 10 CFR 54.4. The intended functions that are the bases for including the systems and structures within the scope of subsequent license renewal are also identified during the scoping process. Screening is the process of 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.

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 2.1.9.1). The methodology is implemented in accordance with an NRC-approved 10 CFR Part 50 Appendix B quality assurance program.

A detailed description of the Turkey Point scoping and screening methodology is provided in Section 2.1. The plant-level scoping results identify the systems and structures within the scope of SLR in Section 2.2. The screening results identify components and structural components subject to AMR and their component intended functions in the following Subsequent License Renewal Application (SLRA) sections:

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

2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 Introduction

This introduction provides an overview of the scoping and screening process used at Turkey Point. Details of how the process is used are included in subsequent sections.

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

If any portion of a mechanical system met the scoping criteria of 10 CFR 54.4, it was included within the scope of license renewal. The systems in the scope of license renewal were evaluated to determine the system components that support the identified system intended function(s). Section 2.3 provides details on the boundaries of in-scope mechanical systems. These boundaries are also depicted on the subsequent license renewal boundary drawings (SLRBD). The in-scope boundaries of the mechanical systems are highlighted in color (green, blue, or red). Mechanical components that are required to perform or support safety-related functions (10 CFR 54.4(a)(1)) or that are required to demonstrate compliance with one of the five license renewal regulated events (10 CFR 54.4(a)(3)) are shown highlighted in green. Nonsafety-related mechanical components that are required for functional support of equipment that are included in the scope of license renewal for 10 CFR 54.4(a)(1) are also highlighted green. Nonsafety-related mechanical components that are included within the scope of license renewal because component failure could prevent the accomplishment of a safety-related function due to potential physical interaction with safety-related SSCs are shown highlighted in blue. Nonsafety-related mechanical components that are included within the scope of 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. Additional details on scoping evaluations and SLRBD development are included in Section 2.1.5.

If any portion of a structure met the scoping criteria of 10 CFR 54.4, the structure was included within the scope of subsequent license renewal. Structures were then further evaluated to determine those structural components that are required to perform or support the identified structure intended function(s). The portions of each structure that are required to support the subsequent license renewal intended function(s) of a specified structure are identified and described in Section 2.4. Additional details on the scoping evaluation's development are provided in Section 2.1.5.

Electrical and I&C systems were scoped using the same methodology as mechanical systems and structures per the scoping criteria in 10 CFR 54.4 (a)(1), (a)(2), and (a)(3). Electrical and I&C components that are part of in-scope electrical and I&C systems and in-scope mechanical systems were included within the scope of subsequent license renewal. Further system evaluations to determine which electrical components were required to perform or support the system intended functions were not performed during the scoping process. 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 subsequent license renewal to identify the long-lived and passive structures and components subject to an AMR. The passive intended functions of structures and components subject to AMR were also identified. Additional details on the screening process are provided in Section 2.1.6.

Selected components, such as equipment supports, structural items, and passive electrical components, were scoped and screened as commodities. The structural commodities were evaluated for each in-scope structure and electrical commodities were evaluated collectively. Passive structural and electrical commodities are identified in Section 2.4 and Section 2.5, respectively.

2.1.2 Information Sources Used for Scoping and Screening

In addition to the Updated Final Safety Analysis Report (UFSAR) and Technical Specifications, the design basis documents (DBDs), the component database, piping and instrumentation diagrams (P&IDs), the Turkey Point Fire Shutdown Analysis Essential Equipment List and Basis Document, station blackout (SBO) equipment list, environmental qualification (EQ) documentation, original license renewal documentation, and other CLB references were relied upon to a great extent in performing scoping and screening for Turkey Point. A brief discussion of these sources is provided.

2.1.2.1 DBDs

In response to an NRC Safety System Functional Inspection on the Turkey Point auxiliary feedwater (AFW) system performed in August 1985, DBDs were prepared for accident mitigation and support systems, selected licensing issues, and UFSAR Chapter 14 accident analyses. DBDs are a tool to explain the requirements behind the design rather than describing the design itself. DBDs are intended to complement other upper-tier documents, such as the UFSAR and Technical Specifications, and are controlled and updated.

2.1.2.2 Component Database

Specific component information for structures, systems, and components at Turkey Point can be found in the controlled component database. The plant component database is called the Nuclear Asset Management Suite (NAMS). NAMS contains as-built information on a component level and consists of multiple data fields for each component, such as design-related information, safety and seismic classifications, safety classification bases, and component tag, type, and description. Information used in this application is current with NAMS as of February 1, 2017.

2.1.2.3 P&IDs

Turkey Point was designed and built prior to the issuance of present-day nuclear power plant guidance documents for American Society of Mechanical Engineers (ASME) Code boundaries and quality group classifications. Quality group classifications for Turkey Point were established considering the Turkey Point current licensing basis (CLB) and various industry codes and standards, including Regulatory Guide 1.26, 10 CFR 50.55a, and ASME Section XI. Quality group classification boundaries for safety-related systems are delineated on P&IDs and provide a basis for ASME Section XI programs.

Various reference documents refer to “ASME Section III Code Class 1, 2, and 3” or “Safety Class 1, 2, and 3” for safety-related components. The corresponding classifications reflected on the P&IDs for Turkey Point Units 3 and 4 are uniformly referred to as “Quality Group A, B, and C.” The classification safety-related (SR) has been used to identify those systems or portions of systems that are important to safety, but for which there are no specific commitments contained within the ASME Section XI program.

2.1.2.4 Turkey Point Fire Shutdown Analysis Essential Equipment List and Basis Document

The Turkey Point Fire Shutdown Analysis Essential Equipment List and Fire Shutdown Analysis Basis Document were used in determining equipment required for the support of fire protection. Specifically, these documents were used to identify credited fire protection equipment that is not classified as safety-related and/or already included within the scope of subsequent license renewal.

2.1.2.5 SBO Equipment Lists

The SBO equipment lists provide details on specific equipment required for the support of SBO. These lists were used to identify components and equipment credited for SBO that were not classified as safety-related and/or not already included within the scope of license renewal. Per Reference 2.1.9.18, additional equipment is required for the restoration of offsite power that is not part of the required equipment for SBO. This additional equipment is also within the scope of subsequent license renewal.

2.1.2.6 EQ Documentation

The EQ list provides a detailed listing of all equipment and components that must be environmentally qualified for use in a harsh environment at Turkey Point. In addition to

UFSAR Section 8.2.2.2, this list was used to identify equipment that must meet specific environmental qualifications regardless of safety classification.

2.1.2.7 Original License Renewal Documentation

Documentation from the original LRA for Turkey Point was used as a starting point for component materials and environments. This documentation includes the original scoping, screening, and AMR reports.

2.1.2.8 Other CLB References

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

- NRC Safety Evaluation Reports including NRC staff review of Turkey Point licensing submittals. Some of these documents may contain licensee commitments.
- Licensing correspondence including 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 which can provide additional information about the requirements of characteristics associated with the evaluated systems, structures, or components.

2.1.3 Technical Reports

Technical reports were prepared in support of the subsequent license renewal application. Engineers experienced in nuclear plant systems, programs, and operations prepared, reviewed, and approved the technical reports. The technical reports contain evaluations and bases for decisions or positions associated with subsequent license renewal requirements as described below. Technical reports are prepared, reviewed, and approved in accordance with controlled project procedures, and are based on CLB source documents described in Section 2.1.2. All of this work was performed under an NRC-approved Appendix B quality assurance program.

2.1.3.1 Subsequent License Renewal Systems and Structures List

Criteria for determining which SSCs should be reviewed and evaluated for inclusion in the scope of SLR is provided in 10 CFR 54.4.

The scoping process to identify systems and structures that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) is performed on systems and structures using documents that form the CLB and other information sources. The CLB for Turkey Point Units 3 and 4 has been defined in accordance with the definition provided in 10 CFR 54.3. The key information sources that form the CLB include the

UFSAR, Technical Specifications, and the docketed licensing correspondence. Other important information sources used for scoping are further described in Section 2.1.2.

The aspects of the scoping process used to identify systems and structures that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) are described in Sections 2.1.3.2, 2.1.3.3, and 2.1.3.4, respectively. The initial step in scoping is defining the entire plant in terms of major systems and structures. As no single document source exists for Turkey Point, a scoping technical report was prepared to establish a comprehensive list of license renewal systems and structures and to document the basis for the list. The list of systems and structures was generated using NAMS and expanded upon using site plan drawings to ensure all structures were captured. Scoping was done independently for systems and structures.

The grouping of the Turkey Point subsequent license renewal systems and structures is based on the guidance provided in NEI 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal* (Reference 2.1.9.1). The complete list of systems evaluated in the scoping technical report 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 SSCs that are part of the CLB and do not have design or functional requirements related to the 10 CFR 54.4 (a)(1), (a)(2), or (a)(3) scoping criteria. These include: driveways and parking lots, temporary equipment, health physics equipment, portable measuring and testing equipment, tools, and motor vehicles. Additional structures and equipment were excluded prior to the scoping process based on other aspects of the CLB. These structures and equipment are detailed in the following sections.

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

Safety-related systems and structures are included within the scope of SLR in accordance with 10 CFR 54.4(a)(1) scoping criterion. NAMS identifies safety-related components via a configuration controlled data field. In the mid-1980s, Turkey Point established safety classifications for systems and structures at the component level consistent with the definition of safety-related SSCs provided in the Florida Power and Light (FPL) Quality Assurance Program and the Turkey Point CLB.

In accordance with Turkey Point plant procedures, safety-related is defined as SSCs that are relied upon during or following a design basis event (DBE) to ensure:

- The integrity of the reactor coolant pressure boundary,
- The capability to shut down the reactor and maintain it in a safe shutdown condition; or
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures that are comparable to the guideline

exposures of 10 CFR 100 or as referred to in 10 CFR 50.34 or 10 CFR 50.67 as applicable.

This definition is technically equivalent to 10 CFR 54.4(a)(1) for purposes of license renewal scoping. No safety-related components have been excluded from the scope of subsequent license renewal.

In June of 2011 the NRC issued an SER (Reference 2.1.9.17) accepting Turkey Point's implementation of Alternate Source Term (AST); therefore, 10 CFR 50.67 requirements are applicable to Turkey Point. As described in the SER, no new electrical components were added to the Turkey Point 10 CFR 50.49 program as a result of the AST adoption and 10 CFR 50.67 was not adopted for the EQ of electrical equipment.

Safety classifications of SSCs are included in NAMS and were established based on reliance on the SSCs during and following DBEs, which include design basis accidents (DBAs), anticipated operational occurrences, natural phenomena, and external events. The DBEs considered for the Turkey Point CLB are consistent with 10 CFR 50.49(b)(1). UFSAR Chapter 14 provides the DBE accident analyses for Turkey Point Units 3 and 4.

Natural phenomena and external events are described in UFSAR Chapter 2 and in appropriate sections of the DBDs. Structures designed to withstand DBEs, natural phenomena, and external events are described in UFSAR Chapter 5.

Two of the DBEs, accidental liquid release and accidental gas release, are analyzed for offsite radiological consequences and do not involve analyses related to the reactor coolant pressure boundary or the capability to shut down the reactor and maintain it in a safe shutdown condition. Table 2.1-1 provides the radiological consequences of these DBEs from UFSAR Sections 14.2.2 and 14.2.3. The offsite dose analyses indicate that the radiological consequences of accidental liquid release and accidental gas release are small fractions of 10 CFR 50.67 limits. As a result, the SSCs related to the prevention and/or mitigation of these DBEs do not meet the scoping criteria of 10 CFR 54.4 (a)(1)(iii). This approach is consistent with Turkey Point's original LRA and CLB. However, these SSCs were evaluated for possible inclusion in SLR scope relative to the criteria of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3). These components are part of either the chemical and volume control system or the waste disposal systems. Evaluation of these components is included in their system's screening technical report.

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

- The UFSAR, Technical Specifications, docketed licensing correspondence, DBDs, NAMS, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criteria of 10 CFR 54.4(a)(1) were identified for each system and structure determined to be safety-related.

The scoping process to identify safety-related systems and structures for Turkey Point is consistent with and satisfies the criteria in 10 CFR 54.4(a)(1).

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

10 CFR 54.4(a)(2) states that SSCs within the scope of subsequent license renewal include nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of the functions identified for safety-related SSCs. The method utilized for this scoping criteria is consistent with NUREG-2192 (Reference 2.1.9.2) and NEI 17-01. Note that Section 3.1.2 of NEI 17-01 references NEI 95-10, Rev. 6, Appendix F, for industry guidance for 10 CFR 54.4(a)(2) scoping criteria.

Consistent with this guidance, the nonsafety-related SSCs that are within the scope of SLR for Turkey Point fall into three categories:

- Nonsafety-related SSCs that may have the potential to prevent satisfactory accomplishment of safety functions,
- Nonsafety-related SSCs directly connected to safety-related SSCs that provide structural support for the safety-related SSCs, and
- Nonsafety-related SSCs that are not directly connected to safety-related SSCs but have the potential to affect safety-related SSCs through spatial interactions.

The first item includes nonsafety-related SSCs credited as a mitigative design feature or for providing a system function relied on by safety-related SSCs in the CLB. These nonsafety-related SSCs are identified by reviewing the Turkey Point UFSAR and other CLB documents. In addition, a supporting system review was performed to identify any nonsafety-related system that supports a safety-related intended function of a system included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1). Any nonsafety-related systems identified during this review are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2).

The remaining two items concern nonsafety-related systems with the potential for physical or spatial interaction with safety-related SSCs. Scoping of these systems is the subject of NEI 95-10, Appendix F. To assure complete and consistent application of 10 CFR 54.4(a)(2) requirements and NEI 95-10, two technical basis documents were prepared. The first document addresses nonsafety-related SSCs directly connected to safety-related SSCs that provide structural support for the safety-related SSCs. The second document addresses nonsafety-related SSCs that are not directly connected to safety-related SSCs but have the potential to affect safety-related SSCs through spatial interactions. Turkey Point chose to implement the preventive option as described in NEI 95-10 to address the potential for spatial interactions.

Figure 2.1-1 provides a flowchart presenting the method for addressing 10 CFR 54.4(a)(2) and identifying where in the SLRA the applicable SSCs are evaluated. Additional detail on the application of the 10 CR 54.4(a)(2) scoping criterion is provided in Section 2.1.5.2.

The scoping process to identify nonsafety-related systems and structures that can affect safety-related systems and structures for Turkey Point is consistent with and satisfies the criteria in 10 CFR 54.4(a)(2).

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

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

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

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

2.1.3.4.1 Fire Protection (10 CFR 50.48)

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) are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3) requirements. Fire protection features and commitments are described in UFSAR Section 9.6.1 and the DBDs.

The design of the Turkey Point Units 3 and 4 fire protection program is based upon the defense-in-depth concept. Multiple levels of protection are provided so that should a fire occur, it will not prevent safe plant shutdown and the risk of a radioactive release to the environment is minimized. These levels of protection include fire prevention, fire detection and mitigation, and the capability to achieve and maintain safe shutdown should a fire occur. This protection is provided through commitments made to NFPA 805. Fire protection features and commitments are described in detail in DBD Volume 23, Fire Protection System NFPA-805 Design Basis.

Systems and structures in the scope of SLR for fire protection include those required for compliance with 10 CFR 50.48(c) and commitments made to the National Fire Protection Association (NFPA) Standard 805 (Reference 2.1.9.4). Equipment relied on for fire protection includes SSCs credited with fire prevention, detection, and mitigation in areas containing equipment important to safe operation of the plant, as well as systems that contain plant components credited to maintain the nuclear fuel in a safe and stable condition. For Turkey Point, the NFPA 805 licensing basis for a safe and stable condition in the event of a fire starting with the reactor in Mode 1, 2, or 3 is to maintain safe and stable conditions in Mode 3 with the ability to cooldown and place the RHR system (RHRS) in service, if necessary.

The nuclear safety capability assessment (NSCA) is the term used by NFPA 805 to represent the safe shutdown analysis (SSA) within the context of NFPA 805.

The essential equipment list is the list of minimum equipment necessary to bring the plant to cold shutdown as determined by the fire SSA, fire probabilistic risk analysis (FPRA), and non-power operations (NPO) fire analysis. The equipment included in the essential equipment list was based on the system functions (e.g., RCS makeup, boration, RHR, etc.) required to achieve safe and stable conditions as defined in NRC Generic Letter (GL) 81-12 (Reference 2.1.9.5) and NFPA 805. The essential equipment list also contains power generation and distribution equipment that are required for the operation of the listed components.

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

- The UFSAR, Technical Specifications, essential equipment list, SSA, licensing correspondence, DBDs, NAMS, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for fire protection were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for fire protection for Turkey Point is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3). Systems and structures in scope of subsequent license renewal for fire protection are shown in Tables 2.2-1, 2.2-2, and 2.2-3.

2.1.3.4.2 Environmental Qualification (10 CFR 50.49)

Certain safety-related electrical components are required to withstand environmental conditions that may occur during or following a DBA per 10 CFR 50.49. The criteria for determining which equipment requires EQ are identified on the Turkey Point EQ list for 10 CFR 50.49 and are indicated in UFSAR Appendix 8A.3:

Electric equipment covered in 10 CFR 50.49 is characterized as follows:

(a). Safety-related electric equipment that is relied upon to remain functional during and following design basis events to insure

(i) the integrity of the reactor coolant boundary,

(ii) the capability to shut down the reactor and maintain it in a safe shutdown condition, and

(iii) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the 10 CFR 100 or 50.67 guidelines. Design Basis Events are defined as conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena for which the plant must be designed to ensure functions (i) through (iii) of this paragraph.

(b). Nonsafety-related electric equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions specified previously.

(c). Certain post-accident monitoring equipment (Refer to Regulatory Guide 1.97, Revision 3, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs During and Following an Accident").

For nonsafety-related electrical components whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions, Turkey Point elected not to differentiate between safety-related and nonsafety-related components. If failure of an electrical component can affect safety-related functions, that electrical component is treated as safety-related for EQ purposes.

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

- The UFSAR, Technical Specifications, licensing correspondence, EQ list, and DBDs were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for EQ were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for EQ for Turkey Point is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3). Time-limited aging analyses (TLAAs) associated with environmentally qualified equipment are discussed in Section 4.4. Systems and structures in the scope of subsequent license renewal for EQ are shown in Tables 2.2-1, 2.2-2, and 2.2-3.

2.1.3.4.3 Pressurized Thermal Shock (10 CFR 50.61)

Fracture toughness requirements specified in 10 CFR 50.61 state that licensees of pressurized water reactors (PWRs) evaluate the reactor vessel beltline materials against specific criteria to ensure protection from brittle fracture. See References 2.1.9.6 through 2.1.9.11 for a listing of Turkey Point licensing correspondence related to PTS.

FPL has made two submittals to the NRC regarding pressurized thermal shock. The first was made on January, 23, 1986 (Reference 2.1.9.6) in response to the original version of 10 CFR 50.61. The NRC SE (Reference 2.1.9.7) on this submittal was issued on March 11, 1987 and concluded that the calculated reference temperature for pressurized thermal shock (RT_{PTS}) met 10 CFR 50.61 requirements. When 10 CFR 50.61 was amended on May 15, 1991, FPL made a second submittal on February 13, 1992 (Reference 2.1.9.8). The NRC dispositioned this submittal in their SE on the amendment to recapture the construction period for Turkey Point dated April 20, 1994 (Reference 2.1.9.9). In this SE, the NRC found that the reactor vessels for Turkey Point Units 3 and 4 are below the pressurized thermal shock screening criteria at the expiration of their current licenses. The FPL submittals and NRC Safety Evaluations did not identify the need for specific plant hardware modifications, or reliance on other plant systems. Note that PTS was re-evaluated during the extended power uprate (EPU) project (References 2.1.9.10 and 2.1.9.11); however, this re-evaluation had no effect on the scope of PTS at Turkey Point.

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

- The UFSAR, Technical Specifications, licensing correspondence, DBDs, NAMS, and design drawings were reviewed, as applicable.
- Based on the above, the reactor vessels are the only components relied upon for protection against PTS. Analyses applicable to PTS have been reevaluated and demonstrated that the reactors vessels meet the screening criteria at the end of the subsequent period of extended operation (SPEO) (see Section 4.2.1.

The scoping process to identify systems and structures relied upon and/or specifically committed to for PTS for Turkey Point is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3). Systems and structures in scope of subsequent license renewal for PTS are shown in Tables 2.2-1, 2.2-2, and 2.2-3.

2.1.3.4.4 Anticipated Transient without Scram (10 CFR 50.62)

Anticipated transient without scram (ATWS) is a postulated operational transient that generates an automatic scram signal, accompanied by a failure of the reactor protection system to automatically shutdown the reactor. The ATWS rule (10 CFR 50.62) requires improvements in the design and operation of light-water cooled water reactors to reduce the likelihood of failure to automatically shutdown the reactor following anticipated transients, and to mitigate the consequences of an ATWS event.

This requirement has been satisfied by the addition of the ATWS Mitigating System Actuating Circuitry (AMSAC), which in addition to the requirements of 10 CFR 50.62 to automatically initiate the auxiliary feedwater system and trip the turbine, will trip the control rod motor-generator set output breakers which will trip the reactor. AMSAC serves as a nonsafety-related backup protective system to the reactor protection system (RPS) by preventing overpressurization of the reactor coolant system, conservation of steam generator inventor, and insertion of the reactor control rods follow an ATWS event.

Turkey Point design features related to ATWS events are described in detail in UFSAR Section 7.2.4.

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

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

The scoping process to identify systems and structures relied upon and/or specifically committed to for anticipated transient without scram events for Turkey Point is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3). Systems and structures in scope of subsequent license renewal for ATWS are shown in Tables 2.2-1, 2.2-2, and 2.2-3.

2.1.3.4.5 Station Blackout (10 CFR 50.63)

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

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). SBO does not include the assumption of loss of available AC power to buses fed by (1) station batteries through inverters or (2) alternate AC sources, nor does it assume a concurrent single failure or design basis accident.

Turkey Point's design satisfies the SBO Rule by providing for a unit cross-tie at the 4.16 KV level. Specifically, resolution of the SBO issue for the Turkey Point nuclear units is by use of an alternate safety-related, Class 1E, seismic Class/Category I, power source with the ability to align the source to the SBO unit within 10 minutes of confirmation of a station blackout condition

Each EDG is sized to maintain both units in Hot Standby for the postulated station blackout scenario, which has an assumed duration of eight hours. UFSAR Tables 8.2-5a and 8.2-5b demonstrate that all of the auto-connect loads and required manual loads associated with an EDG and its respective unit for a loss of offsite power condition, plus the additional loads required on the opposite unit, can be supplied by any one EDG. Thus manual connection of the SBO cross-tie, during SBO conditions, provides an adequate power supply for both units to maintain Hot Standby conditions. SBO load lists were developed to identify the specific loads for any single EDG during an SBO event.

Although not a requirement of the accepted station blackout analysis, NUREG-2192, Section 2.5.2.1.1 Components Within the Scope of SBO (10 CFR 50.63) specifies that the plant portion of the offsite power system that is used to connect the plant to the offsite power source meets the requirements of 10 CFR 54.4(a)(3). This recovery path includes the electrical distribution equipment out to the first circuit breaker with the offsite distribution system (i.e., equipment in the switchyard). This path includes the circuit breakers that connect to the startup transformers, the startup transformers themselves, the intervening overhead circuits between the distribution system circuit breaker and the startup transformer, the intervening circuit between the startup transformer and onsite electrical distribution system, and the associated control circuits and structures.

Design features to satisfy the SBO Rule are described in UFSAR Section 8.2.2.2. Turkey Point licensing correspondence related to SBO are listed as References 2.1.9.12 through 2.1.9.14.

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

- The UFSAR, Technical Specifications, licensing correspondence, DBDs, NAMS, and design drawings were reviewed, as applicable.

- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for SBO were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for SBO for Turkey Point is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3). Systems and structures in scope of subsequent license renewal for SBO are shown in Tables 2.2-1, 2.2-2, and 2.2-3.

2.1.4 Interim Staff Guidance Discussion

The NRC has encouraged applicants for subsequent license renewal to address Interim Staff Guidance (ISG) issues in subsequent license renewal applications. All current ISGs have been addressed in NUREG-2191 (Reference 2.1.9.19).

2.1.5 Scoping Procedure

The scoping process is the systematic process used to identify the Turkey Point SSCs within the scope of the license renewal rule. The scoping process was initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure functions and intended functions were identified from a review of the source CLB documents. The system and structure scoping results are provided in Section 2.2.

The Turkey Point scoping process began with the development of a comprehensive list of plant systems and structures, as described in Section 2.1.3.1.

Each Turkey Point system and structure was then reviewed for inclusion in the scope of subsequent license renewal using the criteria of 10 CFR 54.4(a). These criteria are as follows:

- Title 10 CFR 54.4(a)(1) – Safety-related
- Title 10 CFR 54.4(a)(2) – Nonsafety-related affecting safety-related
- Title 10 CFR 54.4(a)(3) – Regulated Events:
    - Fire Protection (10 CFR 50.48)
    - EQ (10 CFR 50.49)
    - PTS (10 FR 50.61)
    - ATWS (10 CFR 50.62)
    - 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.

2.1.5.1 Safety-Related – 10 CFR 50.54(a)(1)

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

Safety-related systems, structures, and components which are those relied upon to remain functional during the following design-basis events (as defined in 10 CFR 50.49(b)(1), to ensure the following functions –

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shutdown the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable.

At Turkey Point, the safety-related components are identified in NAMS. The safety-related classification in NAMS was populated using a controlled procedure that is consistent with the above 10 CFR 50.34(a)(1) criteria) and design verified. The safety-related classification is also considered a controlled attribute in the database, and any modification to a component's safety classification must be design verified.

Safety-related classifications for systems and structures are based on system and structure descriptions and analysis in the UFSAR. Safety-related structures are those structures listed in the UFSAR and classified as Class I. Systems and structures identified as safety-related in the UFSAR meet the criteria of 10 CFR 54.4(a)(1) and are included within the scope of license renewal. Safety-related components in NAMS were also reviewed, and the systems and structures that contained these components were also included within the scope of license renewal. The review also confirmed that all plant conditions, including conditions of normal operation, internal events, anticipated operational occurrences, DBAs, external events, and natural phenomena as described in the CLB, were considered for license renewal scoping.

2.1.5.2 Nonsafety-Related Affecting Safety-Related – 10 CFR 50.54(a)(2)

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

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

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

- Nonsafety-related SSCs that may have the potential to prevent satisfactory accomplishment of safety functions,

- Nonsafety-related SSCs directly connected to safety-related SSCs that provide structural support for the safety-related SSCs, and
- Nonsafety-related SSCs that are not directly connected to safety-related SSCs but have the potential to affect safety-related SSCs through spatial interactions.

These categories are discussed in detail below.

2.1.5.2.1 Nonsafety-Related SSCs with Potential to Prevent Satisfactory Accomplishment of Safety Functions

This category addresses nonsafety-related SSCs that are required to function in support of subsequent license renewal intended functions of safety-related SSCs. This functional requirement distinguishes this category from other categories where the nonsafety-related SSCs are only required to maintain adequate integrity to preclude structural failure or spatial interaction.

Nonsafety-Related SSCs Credited Design Features in the CLB

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

Cranes

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

High-Energy Line Break (HELB)

For Turkey Point, a high-energy piping system is defined as a system with a service temperature greater than 200°F and design pressure greater than 275 psig, and greater than 1-inch nominal pipe diameter. Non-safety-related whip restraints, jet impingement shields, blowout panels, etc. that are designed and installed to protect safety-related equipment from the effects of a HELB are within the scope of SLR per 10 CFR 54.4(a)(2).

Missiles

Missiles can be generated from internal events such as failure of rotating equipment or external events. Inherent non-safety-related features that protect safety-related equipment from internal and external missiles are within the scope of SLR per 10 CFR 54.4(a)(2).

Flooding

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

<u>Nonsafety-Related SSCs Required to Functionally Support Safety-Related SSCs</u>

In some cases, safety-related SSCs may rely on certain nonsafety-related SSCs to perform a system function. As such, these nonsafety-related SSCs are within the scope of SLR per 10 CFR 54.4(a)(2).

These nonsafety-related SSCs include the following:

- The Unit 3 emergency diesel generator (EDG) building heating, ventilation and air conditioning (HVAC) equipment is required to function to ensure the 3A and 3B EDG engine horsepower ratings are maintained.
- Control building HVAC equipment provides cooling to safety-related direct current (dc) equipment and inverters.
- Containment purge debris screens provide a filtration function to support the containment isolation function of containment purge valves.
- The auxiliary building HVAC equipment is required to provide long-term cooling to safety-related components and structures.
- The auxiliary building electrical equipment room HVAC is required to provide long-term cooling to safety-related components and structures.
- The RHR room sump pumps are credited for internal flooding events in the auxiliary building.
- Turbine building ventilation is required to provide cooling to the rooms containing the safety-related 480V load centers and the 4160V switchgear.
- Instruments in the turbine system that provide input to the reactor protection system (RPS) are included in the scope of license renewal.

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

2.1.5.2.2 Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs that Provide Structural Support for the Safety-Related SSCs

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

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

The following criteria from Appendix F of NEI 95-10 apply to the identification of the first seismic or equivalent anchor at Turkey Point:

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

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

(1) Providing structural support for the safety-related/nonsafety-related interface, and

(2) Ensuring nonsafety-related piping loads are not transferred through the safety-related/nonsafety-related interface.

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

(a) A base-mounted component that is a rugged component and is designed not to impose loads on connecting piping. The SLR scope includes the base-mounted component as it has a support function for the safety-related piping.

(b) A flexible connection is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping system.

(c) A free end of NNS piping, such as a drain pipe that ends at an open floor drain.

(d) For NNS piping runs that are connected at both ends to SR piping, include the entire run of NNS piping.

For Turkey Point, the following methods (e) and (f) may be used to define conservative end points for the portion of NNS piping attached to SR piping to be included in the scope of SLR. The basis for these methods is documented in the Turkey Point SLR nonsafety-related SSCs directly connected to safety-related SSCs technical report.

(e) A point where buried piping exits the ground. The buried portion of the piping should be included in the scope of SLR. Turkey Point buried piping is well founded on compacted soil that is not susceptible to liquefaction based on the seismic reevaluations performed for Turkey Point as part of the post-Fukushima lessons learned.

(f) Consistent with the Turkey Point CLB, a smaller branch line when the moment of inertia ratio of larger piping to the smaller piping is equal to or greater than 25:1, the branch piping may be considered to have no significant effect on the response of the run pipe.

For Turkey Point, these 10 CFR 54.4(a)(2) scoping boundaries have been determined from review of the physical installation details, design drawings, seismic analysis calculations, and plant walkdowns. The associated piping and components included within the scope of license renewal are identified on the SLRBDs in blue. NNS piping attached to SR piping is included in the scope of SLR using the criteria and methods specified above, regardless of location. PTN structures that contain NNS piping attached to SR piping include the containment buildings, auxiliary building, turbine building, main steam and feedwater platforms, control building, emergency diesel generator buildings, and yard structures.

2.1.5.2.3 Nonsafety-Related SSCs that Have the Potential to Affect Safety-Related SSCs through Spatial Interactions

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 license renewal scope in accordance with 10 CFR 54.4(a)(2) requirements. As described in NEI 95-10, Appendix F, there are two options when performing this scoping evaluation: a mitigative option and a preventive option.

To address this requirement of 10 CFR 54.4(a)(2), Turkey Point has chosen the 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 license renewal without consideration of plant mitigative features. The concern is that age-related degradation of nonsafety-related SSCs could lead to adverse interactions with safety-related SSCs that have not been previously considered.

During the original Turkey Point LRA review, NRC staff requested clarification of the Turkey Point scoping criteria for 54.4(a)(2). Specifically, the NRC issued a draft Turkey Point License Renewal Safety Evaluation Report (SER) with several open items (Reference 2.1.9.15). Open Item 2.1.2-1 requested additional justification be provided to demonstrate that age-related failures of nonsafety-related SSCs would not adversely affect safety-related SSCs. The Turkey Point response to Open Item 2.1.2-1 was provided to NRC in FPL letter L-2001-236 (Reference 2.1.9.16), and it addressed all nonsafety-related SSCs that affect safety-related SSCs that are within the scope of license renewal as defined in 10 CFR 54.4(a)(2). Subsequent to this Turkey Point response to initial SER Open Item 2.1.2-1, the (Reference 2.1.9.16) NRC letter issued the final SER for Turkey Point license renewal. In Section 2.1.2-1 of the SER, the NRC states the following:

> *As a result of this supplemental review the applicant brought additional non-safety-related piping segments into the scope of license renewal, provided the results of the associated AMRs, and provided a summary of the programs and activities that will be used to manage aging in these piping systems. The staff's review of the applicant's aging management of components in these piping systems is provided in Section 3.4.16.4 of this*

SER. On the basis of the additional information provided by the applicant, the staff concludes that the applicant has provided sufficient information to demonstrate that all SSCs that meet the 54.4(a)(2) scoping criterion, have been identified as being within the scope of license renewal. Open Item 2.1.2-1 is closed.

The revised scoping process for Turkey Point was accepted by NRC staff for the original Turkey Point LRA. This scoping process is also consistent with the guidance described in NEI 17-01 (Reference 2.1.9.1), which directs applicants to Section 6.0 of Appendix F of NEI 95-10 (Reference 2.1.9.3). Therefore, the process meets NRC guidance for SLR 54.4(a)(2) scoping identified in Section 2.1.3.1.2 and Table 2.1-2 of NUREG-2192 (Reference 2.1.9.2), and, as such, was replicated for SLR at Turkey Point. This approved methodology is as follows:

(a) For each of the major structures of the plant containing both safety-related and nonsafety-related components and structural components, nonsafety-related piping systems containing fluid, steam, or oil were identified. This includes high energy and moderate/low energy piping.

(b) If the identified nonsafety-related piping was determined to be in the scope of license renewal to address the other scoping criteria of 10 CFR 54.4(a), no additional evaluation of this piping was required.

(c) All remaining nonsafety-related piping from the completion of steps (a) and (b) above was then assumed to fail anywhere along its length.

(d) Based on the assumed failures from step (c), and a review of design drawings and plant walkdowns, the effects of pipe whip, jet impingement, physical contact (piping falling such that it physically contacts safety-related equipment), spray, and/or leakage were evaluated to determine if these interactions could potentially impact safety-related component functions. Specifically, the effects of pipe whip, jet impingement, and physical contact were considered for all nonsafety-related high energy piping, and the effects of spray and/or leakage were considered for all other nonsafety-related piping. If the effects of these interactions were determined to impact safety-related functions, the nonsafety-related piping and its associated components were identified as within the scope of license renewal.

(e) If the piping and associated components were determined to be within the scope of license renewal, an aging management review (AMR) evaluation was performed on these components and the required license renewal aging management programs (AMPs) were identified to address the effects of aging.

As stated above, the first step of the preventive option is to determine the Turkey Point structures that house 10 CFR 54.4(a)(1) safety-related equipment. Table 2.1-2 identifies these Turkey Point structures. Based on the unique design features of Turkey Point, nonsafety-related systems in scope for 10 CFR 54.4(a)(2) for spatial interaction are assessed differently based on location. These locations can be grouped into the following three categories:

Containments

Each containment structure is a domed-concrete, steel-reinforced structure that houses the reactor vessel, RCS, and other important systems that interface with the RCS. The following paragraphs describe some of the Turkey Point specific design features inside the containments.

UFSAR Appendix 8A describes the Turkey Point program for the EQ of electrical equipment. Appendix 8A refers to EQ Doc Pac 1001 for the identification of environmental conditions for these components. Section 6.4 of EQ Doc Pac 1001 identifies accident chemical spray as an environment to consider when qualifying electrical equipment inside containment. For Turkey Point, the accident chemical spray environment is created by the operation of the CSS during the Post Accident Operability Time (PAOT). Due to the change in PTN dose analysis methodology to alternate source term as part of the EPU project, the PAOT for the CSS was increased to 31 days post-LOCA. Section 6.4 of EQ Doc Pac 1001 states the equipment inside containment is qualified for an accident chemical spray environment for the full duration of the specified operating time.

Section XIV of the Turkey Point DBD for Selected Licensing Issues describes the Turkey Point history and criteria for the EQ of equipment. Section 3.4 of the DBD states that the EQ of mechanical equipment was originally limited to a radiation qualification review of pumps that are located outside containment. EQ of passive mechanical equipment (i.e., piping) was not considered. However, Section 6.4.1 of EQ Doc Pac 1001 does evaluate the impact of boric acid spray on various exposed metallic materials, including carbon steel, aluminum, stainless steel, cast iron and galvanized steel. The evaluation concludes the corrosion rates for these materials when subjected to a 31-day exposure to chemical spray would be small and would not have a debilitative effect on the materials.

In addition, each Turkey Point containment includes containment level instrumentation which consists of two sub-systems: (1) the containment sump (narrow range) instrumentation, and (2) the containment level (wide range) instrumentation (UFSAR Section 6.5). Both the containment sump and containment level instrumentation consist of redundant level transmitters designed to operate in a normal and post-accident environment. The signal receivers are located outside containment, remote from the sensing elements. Level indication and recording instruments are provided in the control room. In addition the control room has an alarm associated with increasing containment level. The alarm is activated on increasing sump level greater than 1 gpm or a containment sump pump in operation for greater than 3 minutes. Once an alarm is received, the appropriate operating procedures would be used to identify the source of the leakage and implement corrective actions to mitigate the effects of such leakage. It is therefore reasonable to conclude that leakage or spray from moderate energy piping systems inside containment that are not in the scope of SLR and do not require aging management would be detected well before they would result in a loss of function to safety-related components.

As there is no nonsafety-related piping that is high-energy inside the containments at Turkey Point, all high-energy piping is within the scope of SLR in accordance with 10 CFR 54.4(a)(1).

Outdoor Structures

Outdoor structures at Turkey Point that include both nonsafety-related and safety-related SCs are the intake structure, yard structures, turbine building, and main steam and feedwater platforms.

As the equipment in the outdoor structures is designed for outdoor service and is periodically exposed to torrential rains and wind, the safety-related equipment in this area would not be impacted by leakage or spray from moderate- or low-energy piping.

Nonsafety-related, high-energy piping in the outdoor structures is a concern for potential interaction with safety-related equipment. These portions of piping are addressed using the spaces method described above.

Indoor Structures other than Containment

Each unit at Turkey Point includes indoor structures other than containment that house both nonsafety-related and safety-related equipment. These structures include the auxiliary building (which includes fuel handling building and the electrical equipment room), control building, electrical penetration rooms, emergency diesel generator buildings, and the switchgear enclosures located within the turbine building.

All nonsafety-related piping in these buildings is addressed using the spaces approach detailed above.

2.1.5.2.4 Abandoned Equipment

In addition to nonsafety-related SSCs, the potential impact any abandoned equipment could have on safety-related SSCs must also be addressed. To eliminate the potential for indoor abandoned equipment to pose a leakage or spray threat to safety-related equipment, a commitment will be made as part of SLR to revise plant procedures to require the periodic venting and draining of indoor abandoned equipment that is directly connected to in-service systems. Abandoned equipment that remains connected to safety-related SSCs will be included in the scope of license renewal as applicable per the discussion above for nonsafety-related SSCs directly connected to safety-related SSCs. Another acceptable option is to physically disconnect abandoned equipment from in-service equipment. Abandoned equipment that is no longer directly connected to in-service systems will be verified to be vented and drained. The following commitments will be in place and fully implemented prior to entering the subsequent period of extended operation (SPEO) as detailed in commitment number 54 in Appendix A:

(a) Update plant procedures to require the periodic venting and draining of indoor abandoned equipment located outside containment that is directly connected to in-service systems;

(b) Verify that abandoned equipment that is no longer directly connected to in-service systems is vented and drained.

2.1.5.3 Regulated Events – 10 CFR 50.54(a)(3)

In accordance with 10 CFR 50.4(a)(3), the SSCs within the scope of subsequent license renewal include:

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

This scoping technical report identifies the systems and structures required to demonstrate compliance with each of the regulated events. The scoping technical report also includes references to source documents used to determine the scope of components within a system that are credited to demonstrate compliance with each of the applicable regulated events. SSCs credited in the regulated events have been classified as satisfying criteria of 10 CFR 54.4(a)(3) and have been included within the scope of subsequent license renewal. The associated piping and components included within the scope of subsequent license renewal in support of these regulated events are identified on the SLRBDs in green.

2.1.5.4 System and Structure Intended Functions

For the systems and structures within the scope of subsequent license renewal, the intended functions that are the bases for including them within the scope of subsequent license renewal are identified and documented in the scoping technical report. Intended functions define the plant process or condition that must be accomplished in order to perform or support a critical safety function for responding to a DBE or to perform or support a specific requirement of one or more of the five regulated events in

10 CFR 54.4(a)(3). At the major system/structure level, the intended function may be thought of as the reason a system or structure is included within the scope of SLR. For example, the SI System (SIS) is considered in the scope of SLR because it is required to perform the intended function of preventing or mitigating the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR 50.67 requirements. The ultimate goal of intended function identification is to provide a basis for determination of structures and components requiring an AMR in accordance with 10 CFR 54.21(a). The identification of the specific SSC's intended functions supporting the system's intended function is performed as part of the screening process as described in Section 2.1.6. This screening process will provide the final determination of the specific components/structures within the scope of the rule.

2.1.5.5 Scoping Boundary Determination

Systems and structures that are included within the scope of license renewal are then further evaluated to determine the populations 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 in commodity groups and are screened as commodities. The determining of subsequent license renewal system boundaries are further described in the screening procedures for mechanical systems (Section 2.1.6.1), civil structures (Section 2.1.6.2), and electrical and I&C systems (Section 2.1.6.3).

2.1.6 Screening Procedure

This section discusses the screening process used at Turkey Point to determine which components and structural components (collectively abbreviated as SCs) are in the scope of subsequent license renewal and require an AMR.

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

Each application must contain the following information:

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

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

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

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

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

This portion of Turkey Point's IPA methodology is divided into three engineering disciplines: mechanical, civil/structural, and electrical/I&C. The relevant aspects of the component/structural component scoping and screening process for mechanical systems, civil structures, and electrical and I&C systems are described in Section 2.1.6.1, Section 2.1.6.2, and Section 2.1.6.3, respectively. A statement regarding how the SLR boundaries compare to current boundaries for license renewal is included in the “Boundary” discussion in each screening section in Section 2.3, Section 2.4, and Section 2.5. For the systems and structures where the boundaries have not changed, a statement is made that there are no significant differences. The word “significant” is utilized to clarify that there may be minor differences within the boundaries (e.g., valve numbering, locations of vents and drains, etc.), but that the overall boundaries have not changed for SLR.

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

For electrical and I&C systems, a bounding approach as described in NEI 17-01 (Reference 2.1.9.1) is taken. This approach establishes evaluation boundaries, determines the electrical and I&C component commodity groups that compose in-scope systems, identifies specific component and commodity intended functions, and then determines which component commodity groups are subject to an AMR per the criteria of 10 CFR 54.21(a)(1). This approach calls for component scoping after screening has been performed.

Table 2.1-3 gives the definitions of mechanical system, civil structure, and electrical and I&C system component intended functions used in this application for components and structural components.

2.1.6.1 Mechanical Systems

For mechanical systems, the component/structural component screening process is performed on each system identified to be within the scope of SLR. This process evaluates the individual SCs included within in-scope mechanical systems to identify specific SCs or SC groups that require an AMR. Each in scope mechanical system is evaluated in a screening technical report. These reports are grouped based on plant systems as shown in Section 2.3.2, Section 2.3.3, and Section 2.3.4. Where appropriate, multiple systems were included in a single screening technical report. Examples of this include the multiple ventilation systems included in the plant ventilation screening technical report, EDG lube oil and fuel oil addressed in a single screening technical report, and multiple systems included in the plant air screening technical report.

Mechanical system evaluation boundaries were established for each system within the scope of SLR. These boundaries were determined by mapping the pressure boundary associated with the SLR system intended functions onto the system flow diagrams. SLR system intended functions are the functions a system must perform relative to the scoping criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3). The flow diagram boundary drawings associated with each mechanical system within the scope of SLR are identified with the mechanical system screening results described in Section 2.3.

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

- Identify all SCs within that system based on design drawings, original license renewal documents, and the system component list from NAMS.
- Define system evaluation boundaries and eliminate SCs not within the scope of subsequent license renewal (i.e., not required to perform system intended

functions). The system intended function boundaries include those portions of the system that are necessary to ensure that the intended functions of the system will be performed.

- NNS mechanical components and piping segments beyond the SR/NNS boundaries that have the intended function of ensuring structural integrity of the attached SR components under licensing basis design loading conditions are noted as such, and are in the scope of license renewal per 10 CFR 54.4(a)(2). The anchor or equivalent anchor that defines the structural integrity boundary are documented and evaluated the nonsafety-related SSCs directly connected to safety-related SSCs technical report.

- In addition, NNS SSCs not directly connected to SR SSCs whose failure could prevent the performance of a SR system intended function are in the scope of license renewal per 10 CFR 54.4(a)(2). The concern is that age-related degradation of the NNS SSCs could adversely impact SR SSCs through spatial interaction. The NNS SSCs that could spatially interact with SR SSCs are documented in the relevant screening document. The review for potential spatial interactions is documented in the nonsafety-related SSCs not directly connected to safety-related SSCs technical report.

- Components needed to support each of the system-level intended functions identified in the scoping process must be included within the system intended function boundaries. Documentation sources used are described in Section 2.1.2.

- The primary method of designating the system intended function boundaries is to identify the boundaries on system flow diagrams. The system boundaries are based on the system a component is assigned to within NAMS. The basis for not including a component that is assigned to the system and within the subsequent license renewal boundary is explained in the screening technical report.

- Identify SCs that perform their intended functions in a passive manner and thus allow elimination of all active SCs. In the case of valves, fans and pumps, the valve bodies, fan housings and pump casings may perform an intended function by maintaining the pressure boundary and, therefore, would be subject to AMR.

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

- Components within the system intended function boundaries that are both passive and long-lived are identified as subject to AMR in the attachments to each system's screening technical report. The component identification number, name (if available), and type are also listed.

With regard to thermal insulation on mechanical components, no insulation was included in the scope of original license renewal because the insulation did not perform an intended function or directly support the intended functions of other SCs within the scope of license renewal. Based on a review of modifications performed since original license renewal, no changes have occurred that require that insulation be included in the scope of subsequent license renewal. Turkey Point ensures building temperatures are maintained within normal operating environmental qualification design limits, and takes specific corrective action if a condition occurs that would challenge those temperatures. Additionally, adverse localized environments are addressed as part of the Environmental Qualification AMP (B.2.2.4) and the Electrical Insulation for Electrical Cables and Connections not Subject to 10 CFR 50.49 EQ Requirements AMP (B.2.3.38).

Some mechanical components, when combined, are considered complex assemblies. A complex assembly is a predominantly active assembly where the performance of its components is closely linked to the intended function of the entire assembly, such that testing and monitoring of the assembly is sufficient to identify degradation of the components. Examples of complex assemblies at Turkey Point include EDGs, chiller units, compressors that are part of direct expansion cooling units, and air compressor skids. However, to the extent that complex assemblies include piping or components that interface with external equipment, or components that cannot be adequately tested or monitored as part of the complex assembly, those components are identified and subject to AMR. The boundaries identified for each complex assembly are detailed in their respective screening technical reports. This follows the screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192 (Reference 2.1.9.2).

2.1.6.2 Civil Structures

For structures, the screening process is performed on each structure identified to be within the scope of SLR. This method evaluates the SCs included within in-scope structures to identify SCs or SC groups (commodities) that require an AMR. Each in scope structure is evaluated in a screening technical report. There are two separate civil structures screening technical reports. These are divided as shown in Section 2.4 into containment structure and internal structural components (Section 2.4.1) and non-containment structures (Section 2.4.2).

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

- Based on a review of design drawings, the structure component list from NAMS, and plant walkdowns, SCs that are included within the structure are identified. These SCs include items such as walls, supports, and non-current-carrying electrical and I&C components, e.g., conduit, cable trays, electrical enclosures, instrument panels, and related supports.

- The SCs that are within the scope of SLR (i.e., required to perform a SLR system intended function) are identified.

- Design features and associated SCs that prevent potential seismic interactions for in-scope structures housing both safety-related and nonsafety- related systems are identified. This includes a walkdown of each plant area containing both safety-related and nonsafety-related SSCs.

- Component intended functions for in-scope SCs are identified. The component intended functions identified are based on the guidance of NEI 17-01 (Reference 2.1.9.1).

- The in-scope SCs that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) are identified.

- The passive, in-scope SCs that are not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) are identified as requiring an AMR. The determination of whether a passive, in-scope SC has a qualified life or specified replacement time period was based on a review of plant-specific information, including NAMS, maintenance programs and procedures, vendor manuals, and plant OE.

2.1.6.3 Electrical and I&C Systems

The method used to determine which electrical and I&C components are subject to an AMR is organized based on component commodity groups. The primary difference in this method versus the one used for mechanical systems and civil structures is the order in which the component scoping and screening steps are performed. This method was selected for use with the electrical and I&C components since most electrical and I&C components are active. Thus, the method selected provides the most efficient means for determining electrical and I&C components that require an AMR. The method employed is consistent with the guidance in NEI 17-01 (Reference 2.1.9.1).

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

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

- A description and function for each of the electrical and I&C component commodity groups are identified.

- The electrical and I&C component commodity groups that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) are identified.

- For the passive electrical and I&C component commodity groups, component commodity groups that are not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) are identified as requiring an AMR. Electrical and I&C component commodity groups covered by the 10 CFR 50.49, Environmental Qualification Program, are considered to be subject to replacement based on qualified life.

- Certain passive, long-lived electrical and I&C component commodity groups that do not support SLR system intended functions are eliminated.

2.1.6.4 Intended Function Definitions

The intended functions that the components and structures must fulfill are those functions that are the bases for including them within the scope of subsequent license renewal. A component intended function is defined as specific component functions, performed by passive long-lived components and structural elements, that support system and structure intended functions. Examples of component intended functions are maintain pressure boundary, support SR equipment, and insulate electrical conductors. Structures and components may have multiple intended functions. Turkey Point 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” (Reference 2.1.9.2).

Table 2.1-3 provides expanded definitions of structure and component passive intended functions identified in this application.

2.1.6.5 Stored Equipment

The CLB for Turkey Point does not take credit for making repairs to equipment in order to perform one or more of the safe shutdown functions or the use of stored equipment. As such, there are no stored components or equipment included within the scope of subsequent license renewal.

2.1.6.6 Consumables

The evaluation process for consumables is consistent with the guidance provided in NUREG-2192, Table 2.1-3. Consumables have been divided into the following four groups for the purpose of SLR: (1) packing, gaskets, component seals and O-rings; (2) structural sealants; (3) oil, grease, and component filters; (4) system filters, fire extinguishers, fire hoses, and air packs.

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

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

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

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

2.1.7 <u>Generic Safety Issues</u>

In accordance with the guidance in NEI 17-01 and NUREG-2192, review of NRC generic safety issues (GSIs) as part of the subsequent license process is required to satisfy a finding per 10 CFR 54.29. GSIs designated as unresolved safety issues (USIs) and High- and Medium-priority issues in NUREG-0933, Appendix B, that involve aging effects for structures and components subject to an AMR or TLAA evaluations, are to be addressed in the SLRA. A review of the version of NUREG-0933 current six months prior to the SLRA submittal determined that there were no outstanding USIs or High- or Medium-priority GSIs. Two GSIs designated as Active, Issue 186 and Issue 193, were reviewed to assure they did not involve aging effects for structures and components subject to an AMR or TLAA evaluations.

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

Issue 193, Boiling Water Reactor (BWR) ECCS (Emergency Core Cooling Systems) Suction Concerns, addresses the possible failure of low-pressure ECCSs due to unanticipated, large quantities of entrained gas in the suction piping form suppression pools in BWR Mark I containments. This issue is not applicable to Turkey Point.

Thus, there are no GSIs involving aging effects for structures and components subject to an AMR or TLAA evaluations that are relevant to the Turkey Point SLR process.

2.1.8 Conclusion

The scoping and screening methods described in Sections 2.1.5 and 2.1.6 were used for the Turkey Point Units 3 and 4 IPA to identify the SSCs that are within the scope of SLR and require an AMR. The methods are consistent with and satisfy the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.1.9 References

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

2.1.9.2 NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” United States Nuclear Regulatory Commission, ADAMS Accession No. ML16274A402.

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

2.1.9.4 NFPA 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants,” 2001.

2.1.9.5 Generic Letter 81-12, “Fire Protection Rule,” February 20, 1981.

2.1.9.6 C.O. Woody, (FPL) letter to H.G. Thompson (NRC), “Turkey Point Units 3 and 4 – 10 CFR 50.61(b)(1) Report,” January 23, 1986.

2.1.9.7 D. G. McDonald (NRC) letter to C. O. Woody (FPL), "Projected Values of Material Properties for Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events - Turkey Point Plant, Units 3 and 4," March 11, 1987.

2.1.9.8 T. F. Plunkett (FPL) letter to U. S. Nuclear Regulatory Commission, "Turkey Points Units 3 and 4 - 10 CFR 50.61(b)(1) Report," February 13, 1992.

2.1.9.9 The NRC Safety Evaluation on the amendment to recapture the construction period for Turkey Point, April 20, 1994.

2.1.9.10 NUREG-1759, “Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4,” April 2002. (ML021280496)

2.1.9.11 NRC Letter to Mano Nazar (FPL), “Turkey Point Units 3 and 4 – Issuance of Amendments Regarding Extended Power Uprate,” dated June 15, 2012. (ML11293A365)

2.1.9.12 W. F. Conway (FPL) letter to U. S. Nuclear Regulatory Commission, "Information to Resolve Station Blackout," April 17, 1989.

2.1.9.13 G. E. Edison (NRC) letter to J. H. Goldberg (FPL), "Turkey Point Units 3 and 4 - Safety Evaluation for Proposed Implementation of the Station Blackout Rule (10 CFR 50.63) (TAC Nos. 68618 and 68619)," June 15, 1990.

2.1.9.14 R. Auluck (NRC) letter to J. H. Goldberg (FPL), "Turkey Point Units 3 and 4 - Supplemental Safety Evaluation for Proposed Implementation of the Station Blackout Rule (10 CFR 50.63) (TAC Nos. 81159 and 81160)," July 31, 1991.

2.1.9.15 NRC Safety Evaluation Report with Open Items Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4, August 2001, Accession No. ML012320225.

2.1.9.16 FPL Letter to NRC, L-2001-236, License Renewal Safety Evaluation Report Open Item and Confirmatory Item Responses and Revised License Renewal Application Appendix A, dated November 1, 2001, Accession No. ML013470150.

2.1.9.17 NRC letter to Mano Nazar (FPL), Turkey Point Units 2 and 4 – Issuance of Amendments Regarding Alternative Source Term (TC Nos. ME1624 and ME1625), Accession No. ML110800666

2.1.9.18 L-2002-071, “Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, Response to NRC Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule for License Renewal” dated April 19, 2002

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

Table 2.1-1
Radiological Consequences for Certain Design Basis Events

Design Basis Event	Radiological Consequences		
	EB	LPZ	CR
Accidental Liquid Release[1]	Negligible	Negligible	N/A
Accidental Gas Release[2]	0.066 rem TEDE[3]	0.013 rem TEDE[4]	0.33 rem TEDE[5]

Notes for Table 2.1-1

1. UFSAR Section 14.2.2 determined, “No credible mechanism exists for accidental release of waste liquids to Biscayne Bay.”
2. Worst case, failure of a gas decay tank.
3. Exclusion boundary (EB), 0-30 days, Branch Technical Position (BTP) 11-5 limit is 0.1 rem TEDE.
4. Low population zone (LPZ), 0-30 days, BTP 11-5 limit is 0.1 rem TEDE.
5. BTP 11-5 does not require control room (CR) dose to be calculated; however the CR limit is 5 rem TEDE.

Table 2.1-2
Structures Containing NNS and SR SSCs Requiring Scoping/Screening 54.4(a)(2) Spatial Interaction

Structure Number	Structure Name
009 111S	Intake Structure
051	Containment Buildings
111A	Emergency Diesel Generator Buildings
111B	Control Building
111D	Yard Structures
111E 037	Auxiliary Building (includes Fuel Handling Buildings and Electrical Equipment Room)
111F	Turbine Building (includes switchgear enclosures)
111G	Electrical Penetration Rooms
111H	Main Steam and Feedwater Platforms

Table 2.1-3
Passive Structure/Component Intended Function

Intended Functions	Definition
Absorb neutrons	Absorb neutrons.
Core support	Provide support and orientation of the reactor core (i.e., the fuel assemblies).
Direct flow	Provide spray shield or curbs for directing flow or provide means of fluid flow diversion within a component (as seen in divider plates, heat exchanger coil shields, vortex diffusers, etc.).
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.
Fire prevention	Provides a rated fire barrier to prevent a fire from spreading outside of a tank.
Flood barrier	Provide flood protection barrier (internal and external flood event).
Flow distribution	Provide a passageway for the distribution of the reactor coolant flow to the reactor core.
Gaseous release path	Provide path for release of filtered and unfiltered gaseous discharge.
Guide instrumentation	Provide a passageway for guidance and protection for incore instrumentation.
Guide rod control cluster assemblies (RCCAs)	Provide guidance of the control rod assemblies.
Guide RCCAs and support RCCAs	Provide support, orientation, guidance, and protection of the control rod assemblies.
Heat sink	Provide heat sink during SBO or design basis accidents.
Heat transfer	Provide heat transfer.
HELB shielding	Provide shielding against HELBs.
Insulate	Insulate and support an electrical conductor
Insulate (thermal)	Inhibit/prevent heat transfer across a thermal gradient.

Table 2.1-3
Passive Structure/Component Intended Function (Continued)

Intended Functions	Definition
Leakage boundary (spatial)	Nonsafety-related component that maintains mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs.
Missile barrier	Provide missile barrier (internally or externally generated).
Pipe whip restraint	Provide pipe whip restraint.
Pressure boundary	Provide pressure-retaining boundary or essentially leak tight barrier so that sufficient flow at adequate pressure is delivered, or provide fission product barrier for containment pressure boundary, or provide containment isolation for fission product retention.
Shelter, protection	Provide shelter/protection to safety-related components and other non-safety components within the scope of license renewal.
Shielding	Provide shielding against radiation.
Shield vessel	Provide gamma and neutron shielding for the reactor pressure vessel.
Spray	Provide water spray.
Structural integrity (attached)	Nonsafety-related component that maintains mechanical and structural integrity to provide structural support to attached safety-related piping and components.
Structural support	Provide structural and/or functional support to safety-related and/or nonsafety-related components.
Throttle	Provide flow restriction.

Figure 2.1-1 — 10 CFR 54.4(a)(2) Evaluation Methodology

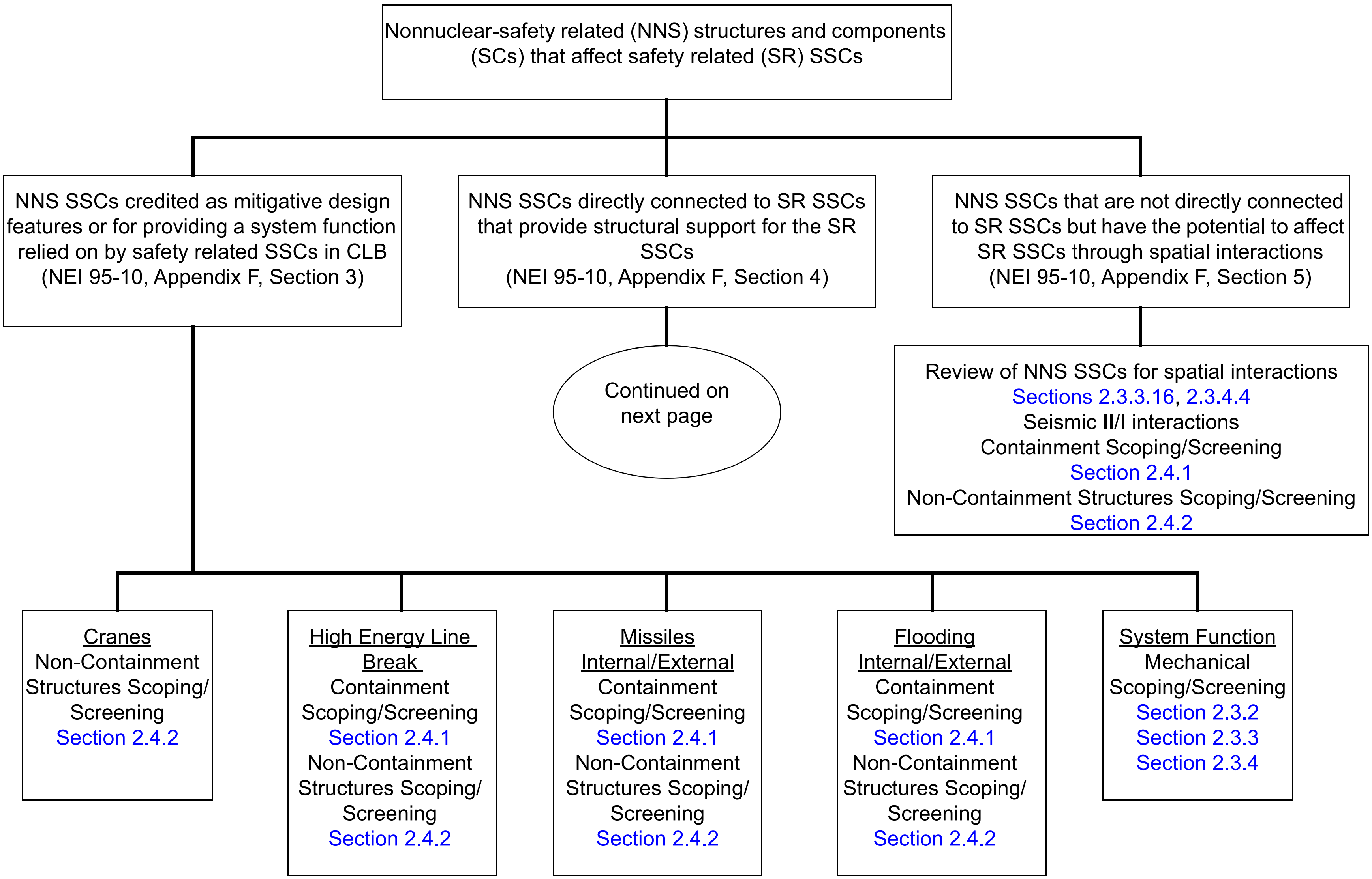
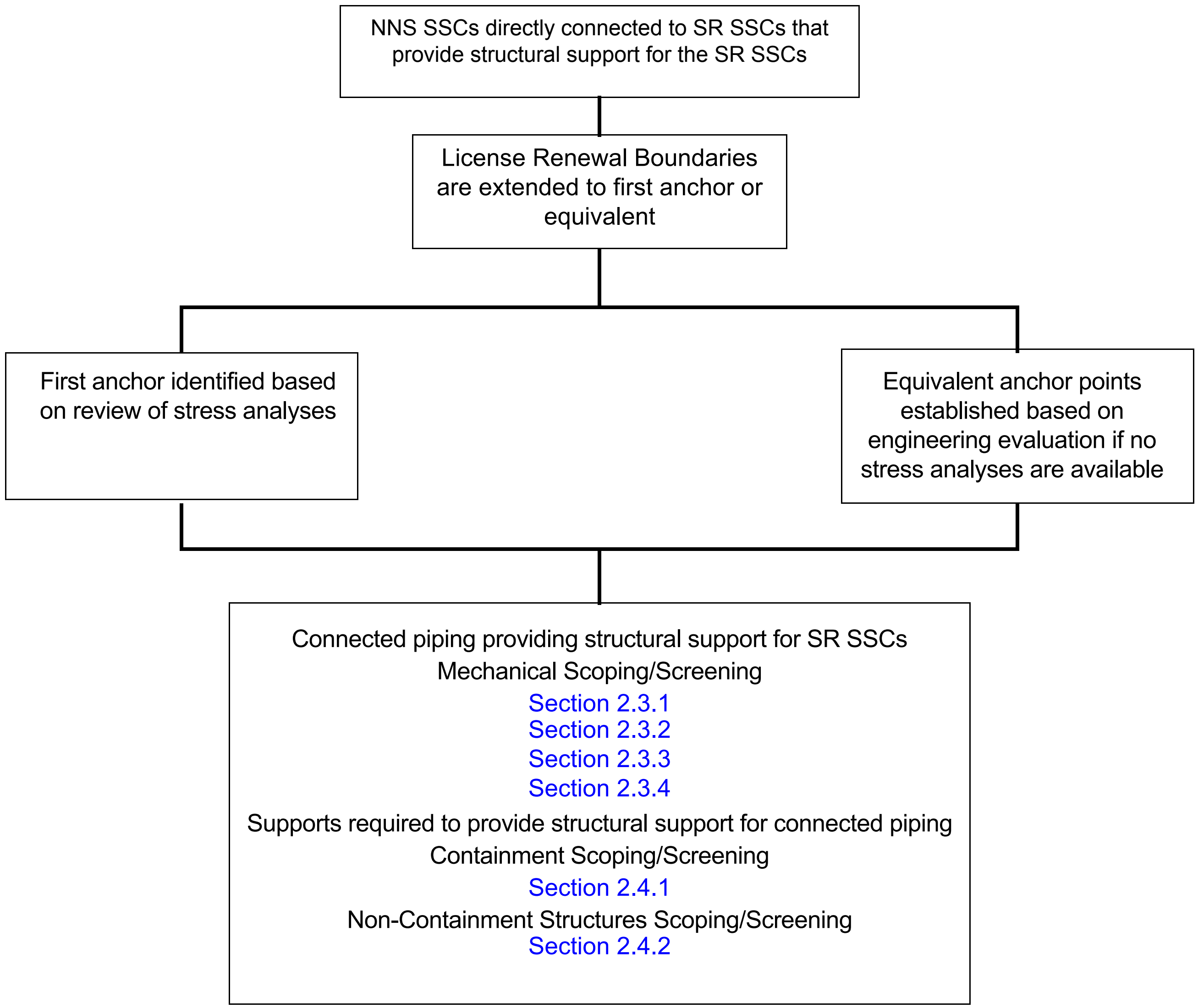


Figure 2.1-1 — 10 CFR 54.4(a)(2) Evaluation Methodology (Continued)



2.2 PLANT LEVEL SCOPING RESULTS

Turkey Point's IPA methodology consists of scoping, screening, and AMRs. This section provides the plant-level scoping results achieved when applying the scoping methodology described in Section 2.1.1 to plant systems and structures.

Tables 2.2-1, 2.2-2, and 2.2-3 provide the plant-level scoping results for mechanical systems, structures, and electrical/I&C systems, respectively. If a system or structure, in whole or in part, meets one or more of the SLR scoping criteria, the system or structure is considered to be within the scope of SLR. The tables also include references to the sections in the SLRA that discuss screening results for in-scope systems and structures.

Table 2.2-1
Subsequent License Renewal Scoping Results for Mechanical Systems

Sys. No.	System Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
008	Turbine Plant Cooling Water	N	N	N	N	N	N	N	
010	Circulating Cooling Water	N	N	N	N	N	N	N	
011	Screen Wash and Chlorination	N	N	N	N	N	N	N	
012	Service Water	N	Y	N	N	N	N	N	2.3.3.16
013	Instrument Air[1]	Y	Y	Y	Y	N	N	Y	2.3.3.9
014	Condenser	N	N	N	N	N	N	N	
015	Amertap	N	N	N	N	N	N	N	
016 017	Fire Protection (includes Transformer Deluge and RCP Oil Collection Systems)	Y	N	Y	N	N	N	N	2.3.3.12
018	Condensate Storage	Y	N	Y	N	N	Y	Y	2.3.4.3
019	Intake Cooling Water	Y	Y	Y	N	N	N	Y	2.3.3.1
020	Primary Water Makeup	Y	Y	Y	N	N	N	Y	2.3.3.5
021	Water Treatment Plant	N	N	N	N	N	N	N	
022A	EDG Air Start	Y	Y	Y	N	N	Y	Y	2.3.3.14
022B	EDG Fuel Oil	Y	Y	Y	N	N	Y	Y	2.3.3.15
022C	EDG Cooling Water	Y	Y	Y	N	N	Y	Y	2.3.3.13
022D	EDG Lube Oil	Y	N	Y	N	N	Y	Y	2.3.3.15
023A	Unit 3 EDG Building HVAC	N	Y	Y	N	N	Y	Y	2.3.3.11.3
025A	Control Room HVAC	Y	N	Y	N	N	N	Y	2.3.3.11.2
025B	Computer/Cable Spread Room HVAC	Y	Y	Y	N	N	N	Y	2.3.3.11.2

Table 2.2-1
Subsequent License Renewal Scoping Results for Mechanical Systems (Continued)

Sys. No.	System Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
025C	Control Building Annex HVAC (DC Equipment and Inverters)	N	Y	Y	N	N	N	Y	2.3.3.11.2
025D	3B, 4B MCC Room HVAC	N	N	N	N	N	N	N	
026	Radwaste Building HVAC	N	N	N	N	N	N	N	
027 028	Control Rod Drives[2]	N	N	N	N	N	N	N	
027A	CRDM Cooling[3]	N	N	N	N	N	N	Y	2.3.3.10
030	Component Cooling Water	Y	Y	Y	Y	N	N	Y	2.3.3.2
032	Sample System - Secondary	Y	Y	Y	N	N	Y	Y	2.3.3.7
033 040A	Spent Fuel Pool Cooling (includes spent fuel assemblies)	Y	Y	N	N	N	N	Y	2.3.3.3
034A	Spent Fuel Storage Area HVAC	N	N	N	N	N	N	N	
035A	New Fuel Storage Area HVAC	N	N	N	N	N	N	N	
036	Sample System - NSSS	Y	Y	Y	Y	N	N	Y	2.3.3.6
041 040B 043	Reactor Coolant System (includes fuel assemblies in the core and Reactor Vessel)	Y	Y	Y	Y	Y	Y	Y	2.3.1
046	CVCS Boron Addition and Recycle	Y	Y	Y	Y	N	N	N	2.3.3.4
047	CVCS Charging and Letdown	Y	Y	Y	Y	N	N	Y	2.3.3.4

Table 2.2-1
Subsequent License Renewal Scoping Results for Mechanical Systems (Continued)

Sys. No.	System Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
050	Residual Heat Removal	Y	Y	Y	Y	N	N	N	2.3.2.5
053	Containment Purge[4]	Y	Y	N	Y	N	N	Y	2.3.2.3
055	Emergency Containment Coolers	Y	N	N	Y	N	N	N	2.3.2.1
057	Normal Containment Coolers	N	N	Y	N	N	N	Y	2.3.3.10
058	Penetration Cooling	N	N	N	N	N	N	N	
060	Auxiliary Building HVAC	N	Y	Y	N	N	N	Y	2.3.3.11.1
060A	Electrical Equip Room HVAC	Y	Y	Y	N	N	N	Y	2.3.3.11.1
061	Waste Disposal	Y	Y	Y	Y	N	N	Y	2.3.3.8
062 064	Safety Injection (includes SI Accumulators)	Y	Y	Y	Y	N	N	Y	2.3.2.4
065	Nitrogen and Hydrogen (NSS)[1]	Y	Y	N	N	N	N	Y	2.3.3.9
067	Process Radiation Monitoring	Y	N	N	N	N	N	N	2.3.2.6
068	Containment Spray	Y	N	N	Y	N	N	N	2.3.2.2
070	Turbine Building Ventilation	N	Y	Y	N	N	N	Y	2.3.3.11.4
071	Steam Generator	Y	Y	Y	Y	N	Y	Y	2.3.1.5 2.3.4.2
072	Main Steam	Y	Y	Y	Y	N	Y	Y	2.3.4.1
073	Condensate	N	Y	N	N	N	N	N	2.3.4.4
074	Feedwater and Blowdown	Y	Y	Y	Y	N	Y	Y	2.3.4.2
075	Auxiliary Feedwater	Y	Y	Y	Y	N	Y	Y	2.3.4.3

Table 2.2-1
Subsequent License Renewal Scoping Results for Mechanical Systems (Continued)

Sys. No.	System Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
076	Turbine Plant Chemical Addition	N	N	N	N	N	N	N	
077	Condensate Polishing	N	N	N	N	N	N	N	
078	S/G Wet Layup[5]	Y	N	N	N	N	N	N	
080	Condensate Recovery	N	N	N	N	N	N	N	
081	Feedwater Heaters, Drains, and Vents	N	Y	N	N	N	N	N	2.3.4.4
082	Secondary Wet Layup[6]	N	Y	N	N	N	N	N	
083	Fukushima FLEX	N	N	N	N	N	N	N	
084	Auxiliary Steam	N	Y	N	N	N	N	N	2.3.4.4
085	Extraction Steam	N	N	N	N	N	N	N	
086	Electro-Hydraulic Control	N	N	N	N	N	N	N	
087	Turbine Lube Oil	N	N	N	N	N	N	N	
088	Gland Steam and Drains	N	N	N	N	N	N	N	
089	Turbine	N	Y	N	N	N	Y	N	2.3.4.1
090	Generator	N	N	N	N	N	N	N	
094	Containment Post-Accident Evaluation	Y	N	N	Y	N	N	Y	2.3.2.6
099	Metal Impact Monitoring	N	N	N	N	N	N	N	
100	Security	N	N	N	N	N	N	N	
101	Breathing Air[1]	Y	N	N	N	N	N	N	2.3.3.9

Table 2.2-1
Subsequent License Renewal Scoping Results for Mechanical Systems (Continued)

Sys. No.	System Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
103	Environmental Monitoring	N	N	N	N	N	N	N	
108	Unit 4 EDG Building HVAC	Y	Y	Y	N	N	Y	Y	2.3.3.11.3

Notes for Table 2.2-1

1. Included in Plant Air.
2. This line item is for electrical portions of the control rod drive only. The mechanical pressure boundary components are addressed with Reactor Vessels in Section 2.3.1.3.
3. Included in Normal Containment Ventilation.
4. Included in Containment Isolation.
5. This system contains safety-related boundary valves to the main steam and feedwater systems. These valves and associated piping are included in the Section 2.3.4.2 screening results for the feedwater system.
6. This system contains valves with a leakage boundary (spatial) intended function that are boundary valves to the condensate system. These valves and associated piping are included in the Section 2.3.4.4 screening results for the condensate system.

Table 2.2-2
Subsequent License Renewal Scoping Results for Structures

Str. No.	Structure Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
009 111S	Intake Structure	Y	Y[1]	Y	N	N	N	Y	2.4.2.10
016A	Fire Rated Assemblies	Y	N	Y	N	N	N	N	2.4.2.9
029	Polar Cranes	N	Y	N	N	N	N	N	2.4.2.13
079E	Water Treatment Plant	N	N	N	N	N	N	N	
051	Containment Buildings	Y	Y[1]	Y	N	N	Y	Y	2.4.1.1
034 038 116	Spent Fuel Storage and Handling (includes Spent Fuel Cask Crane and Spent Fuel Storage)	Y	Y	N	N	N	N	N	2.4.2.14
035 039	New Fuel Storage and Handling (includes New Fuel Storage)	N	N	N	N	N	N	N	
079A	Cooling Canals	N	Y	Y	N	N	N	Y	2.4.2.4
079B	Discharge Structure	N	Y	Y	N	N	N	Y	2.4.2.6
079E	Water Treatment Building	N	N	N	N	N	N	N	
079G	Meteorological Towers	N	N	N	N	N	N	N	
079H	Offsite Communications Tower	N	N	N	N	N	N	N	
079I	4160 V C Bus Switchgear Enclosures	N	N	N	N	N	N	N	
079J	Switchyard Relay Enclosure	N	N	N	N	N	N	N	

Table 2.2-2
Subsequent License Renewal Scoping Results for Structures (Continued)

Str. No.	Structure Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
079K	Diesel Driven Fire Pump Enclosure	N	N	Y	N	N	N	N	2.4.2.5
079L	Satellite Security Stations	N	N	N	N	N	N	N	
079M	I&C Repair Facility	N	N	N	N	N	N	N	
089A	Turbine Gantry Crane	N	Y	N	N	N	N	N	2.4.2.16
100A	Security Barriers	N	N	N	N	N	N	N	
111A	Emergency Diesel Generator Buildings	Y	Y[1]	Y	N	N	Y	N	2.4.2.8
111B	Control Building	Y	Y[1]	Y	N	N	Y	Y	2.4.2.3
111C	Radwaste Building[2]	N	N	N	N	N	N	N	
111D	Yard Structures (includes yard equipment foundations, yard concrete footings for structural steel supports, pipe trenches, and duct banks)	Y	Y[1]	Y	N	N	Y	Y	2.4.2.17
111E 037	Auxiliary Building (includes Fuel Handling Buildings and Electrical Equipment Room)	Y	Y[1]	Y	N	N	N	Y	2.4.2.1
111F	Turbine Building (includes switchgear enclosures)	Y	Y[1]	Y	N	N	Y	Y	2.4.2.15
111G	Electrical Penetration Rooms	Y	Y[1]	Y	N	N	Y	Y	2.4.2.7
111H	Main Steam and Feedwater Platforms	Y	Y[1]	Y	N	N	Y	Y	2.4.2.11

Table 2.2-2
Subsequent License Renewal Scoping Results for Structures (Continued)

Str. No.	Structure Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
111I	Operator RCA Access Station	N	N	N	N	N	N	N	
111K	Plant Vent Stack	N	Y	N	N	N	N	N	2.4.2.12
111L	Technical Support Center	N	N	N	N	N	N	N	
111M	Cold Chemistry Lab	N	Y	N	N	N	N	N	2.4.2.2
111N	Dry Storage Warehouse	N	N	N	N	N	N	N	
111R	New Fuel Storage Building	N	N	N	N	N	N	N	
111T	Access Dress Facility	N	N	N	N	N	N	N	
112A	Nuclear Entrance Building	N	N	N	N	N	N	N	
112B	Nuclear Administration Building	N	N	N	N	N	N	N	
112C	Cafeteria	N	N	N	N	N	N	N	
112D	Warehouse	N	N	N	N	N	N	N	
112E	Machine Shop	N	N	N	N	N	N	N	
112F	Hazardous Materials Storage Facility	N	N	N	N	N	N	N	
112G	Main Truck Gate House	N	N	N	N	N	N	N	
112H	HP Truck Monitoring Building	N	N	N	N	N	N	N	
112I	Nuclear Administration Building Vault	N	N	N	N	N	N	N	
112J	Nuclear Maintenance Building	N	N	N	N	N	N	N	

Table 2.2-2
Subsequent License Renewal Scoping Results for Structures (Continued)

Str. No.	Structure Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
112K	Spare Main Transformer	N	N	N	N	N	N	N	
112L	HP Control Building	N	N	N	N	N	N	N	
112M	SCBA Facility	N	N	N	N	N	N	N	
112O	Steam Generator Storage Facility	N	N	N	N	N	N	N	
112Q	Chemical Storage Building	N	N	N	N	N	N	N	
112R	Other Miscellaneous Buildings	N	N	N	N	N	N	N	
112S	FLEX Equipment Storage Building	N	N	N	N	N	N	N	

Notes for Table 2.2-2

1. These structures contain both safety-related and nonsafety-related SSCs. The potential for nonsafety-related SSCs adversely affecting safety-related SSCs is evaluated using the “spaces approach” and is detailed in Section 2.1.5.
2. Consistent with original license renewal, the radwaste building does not meet one or more of the license renewal scoping criteria in 10 CFR 54.4 even though it was designed and constructed as a Sesimic Category I structure, as described in UFSAR Section 5.3.3 and Appendix 5A. The radwaste building does not house or protect safety-related systems and/or components, is not part of or house a seismic anchor for safety-related components, and does not house any components on the Fire Shutdown Analysis Essential Equipment List. The radwaste building provides collection of fire suppression water, which is considered for NFPA 805 relative to 10 CFR 20 normal operation radiological release. As such, and since 10 CFR 20 releases are not directly part of license renewal regulations or guidance, the radwaste building is not included in the scope of subsequent license renewal.

Table 2.2-3
Subsequent License Renewal Scoping Results for Electrical Systems

Sys. No.	System Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
001	Communications	N	N	Y	N	N	N	Y	2.5
002	240 KV Switchyard	N	N	N	N	N	N	Y	2.5
003	125 VDC and 120 VAC	Y	N	Y	Y	N	Y	Y	2.5
004	Start-Up Transformers	N	N	Y	N	N	N	Y	2.5
005	4.16 KV (includes 4.16 KV portion of System 107)	Y	N	Y	Y	N	Y	Y	2.5
006	480 V Switchgear (includes 480 V portion of System 107)	Y	N	Y	Y	N	Y	Y	2.5
007	480 V MCCs	Y	N	Y	Y	N	Y	Y	2.5
023	Emergency Diesel Generator	Y	N	Y	N	N	Y	Y	2.5
024	Emergency Load Sequencer	Y	N	Y	N	N	Y	Y	2.5
027 028	Control Rod Drives[1]	N	N	N	N	N	N	N	
42	Qualified Safety Parameter Display System (QSPDS)	Y	N	N	N	N	N	N	2.5
049	Reactor Protection	Y	N	Y	N	N	Y	N	2.5
051A	Containment Electrical Penetrations (conductor and non-metallic portions)	Y	N	Y	Y	N	Y	Y	2.5
059	Nuclear Instrumentation (Incore and Excore)	Y	N	Y	Y	N	N	N	2.5
063	Engineered Safeguards	Y	N	N	N	N	N	N	2.5

Table 2.2-3
Subsequent License Renewal Scoping Results for Electrical Systems (Continued)

Sys. No.	System Name	SR	NNS	FP	EQ	PTS	ATWS	SBO	Screening Results Application Section
066	Area Radiation Monitoring	N	N	N	N	N	N	N	
091	Fire and Smoke Detection	N	N	Y	N	N	N	N	2.5
092	Main and Auxiliary Transformers	N	N	N	N	N	N	N	
093	AMSAC	N	N	N	N	N	Y	N	2.5
095	Emergency Response Facility Equipment and Plant Computer	Y	N	N	N	N	N	N	2.5
096	Reactivity Computer	N	N	N	N	N	N	N	
097	Annunciators	N	N	N	N	N	N	N	
098	Underwater TV Camera	N	N	N	N	N	N	N	
104	Plant Lighting	N	N	Y	N	N	N	Y	2.5
113	Lightning Protection	N	N	Y	N	N	N	N	2.5
114	Plant Data System	N	N	N	N	N	N	N	
115	Plant Data System	Y	N	N	N	N	N	N	2.5
120	Condenser Cathodic Protection	N	N	N	N	N	N	N	
139	SG Feed Pump Vibration Monitoring	N	N	N	N	N	N	N	

Notes for Table 2.2-3

1. This line item is for electrical portions of the control rod drive only. The mechanical pressure boundary components are addressed with Reactor Vessels in Section 2.3.1.3.

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL SYSTEMS

The scoping and screening results for mechanical systems consist of lists of components and component groups that require AMR, grouped and presented on a system basis. Brief descriptions of mechanical systems within the scope of SLR are provided as background information. Mechanical system intended functions are provided for in-scope systems. For each in-scope system, components or component groups requiring an AMR are provided. For the sections where the system description applies to the system on each unit, a statement is included indicating that the systems for Units 3 and 4 are essentially identical. The word “essentially” is utilized to clarify that there may be minor differences between the systems on each unit (e.g., valve numbering, locations of vents and drains, etc.), but these differences would not affect the information that follows.

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

- Reactor coolant system (Section 2.3.1)
- Engineered safety features (Section 2.3.2)
- Auxiliary systems (Section 2.3.3)
- Steam and power conversion systems (Section 2.3.4)

As noted in Section 2.1.5.2.3, for nonsafety-related SSCs that are not directly connected to safety-related SSCs, the nonsafety-related SSCs may be in-scope if their failure could prevent the performance of a system safety function. By utilizing the spaces approach, it was determined that the only nonsafety-related mechanical system categories with the potential for spatial interactions are auxiliary systems and steam and power conversion systems. Scoping and screening results associated with these nonsafety-related SCCs with the potential for spatial interactions are presented in Sections 2.3.3.16 and 2.3.4.4, respectively.

With regard to electrical interfaces, the system evaluation boundaries end at the interface between the electrical connections to the mechanical components (e.g., pump coupling to a motor). Electrical components, including motors, power and control cabling and power supplies, are addressed with other electrical components in Section 2.5.

The interface boundary with plant instrumentation is established at the mechanical inlet connection to the device. Instrumentation is also addressed with other electrical components in Section 2.5.

2.3.1 Reactor Coolant System

Description

The reactor coolant system (RCS) consists of the components designed to contain and support the nuclear fuel, contain the reactor coolant, and transfer the heat produced in the reactor to the steam and power conversion systems for the production of electricity. The RCS for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The RCS consists of three loops connected in parallel to the reactor vessel, with each loop containing a steam generator and a reactor coolant pump (RCP). The system also includes a pressurizer, pressurizer relief tank (PRT), connecting piping, and instrumentation necessary for operational control. The RCPs circulate cold leg water through the reactor vessel where heat produced by the fission process is transferred to the coolant. The RCS transfers the heat generated in the core to the steam generators, where steam is produced to drive the turbine generator. Cooling water is circulated at the flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a solvent for the neutron absorber used in chemical shim control, and as a neutron moderator and reflector. The RCS provides a boundary for containing the coolant under operating temperature and pressure conditions. It also confines radioactive material and limits uncontrolled release of the reactor coolant to the secondary system and other parts of the plant to acceptable values. The inertia of the RCPs provides the necessary flow during a pump coast-down. The layout of the system assures natural circulation capability following a loss of forced flow to permit decay heat removal without overheating the core.

The three loops interface with various other systems, e.g., safety injection (SI), residual heat removal (RHR), chemical and volume control system (CVCS), etc.

Boundary

The SLR boundaries are shown on the SLR boundary drawings (SLRBDs) listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3:
5613-M-3036, Sheet 1
5613-M-3041, Sheet 1
5613-M-3041, Sheet 2
5613-M-3041, Sheet 3
5613-M-3041, Sheet 4
5613-M-3047, Sheet 2
5613-M-3047, Sheet 3
5613-M-3050, Sheet 1
5613-M-3062, Sheet 1
5613-M-3064, Sheet 1

Turkey Point Unit 4:
5614-M-3036, Sheet 1
5614-M-3041, Sheet 1
5614-M-3041, Sheet 2
5614-M-3041, Sheet 3
5614-M-3041, Sheet 4
5614-M-3047, Sheet 2
5614-M-3047, Sheet 3
5614-M-3050, Sheet 1
5614-M-3062, Sheet 1
5614-M-3064, Sheet 1

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Transfer heat from the reactor core to the steam generators to prevent core damage during accident conditions.

(2) Provide a barrier to prevent the release of fission products from the reactor core to the environment.

(3) Provide a flow path to support reactor core cooling.

(4) Provide RCS pressure control (includes overpressure protection).

(5) Contain, align, and support the reactor core and provide for interfaces for reactor control.

(6) Provide for venting non-condensable gases and steam following postulated accidents or events.

(7) Provide for low-temperature overpressure mitigation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection, for the EQ Program, for PTS, for ATWS and for SBO events.

UFSAR References

Section 4.0

Components Subject to AMR

The RCS is reviewed as the following subsystems. The fuel assemblies are periodically replaced based on burnup and are not subject to AMR.

- Reactor Coolant and Connected Piping (Section 2.3.1.1)
- Pressurizers (Section 2.3.1.2)
- Reactor Vessels (Section 2.3.1.3)
- Reactor Vessel Internals (Section 2.3.1.4)
- Steam Generators (Section 2.3.1.5)

2.3.1.1 Reactor Coolant and Connected Piping

2.3.1.1.1 Reactor Coolant Piping

Description

Reactor coolant piping consists of piping (including fittings, branch connections, flow restrictors, and thermowells), pressure retaining parts of valves, and bolted closures and connections. Reactor coolant piping is presented in two parts:

- Class 1 piping
- Non-Class 1 piping

Class1 Piping

Class 1 piping includes the main coolant piping; pressurizer surge, spray, safety, and relief lines; vents, drains, instrumentation lines, and orifices; and Class 1 portions of ancillary systems attached to the RCS. Ancillary systems attached to the RCS include RHR, SI, primary sampling, and CVCS.

Non-Class 1 Piping

Several non-Class 1 reactor coolant components are within the scope of SLR. These non-Class 1 reactor coolant components include:

- Instrumentation tubing and fittings downstream of flow restrictors.
- Inner reactor vessel flange O-ring leak detection line tubing, fittings and valves.
- Reactor vessel head vent piping, fittings, and valves downstream of the restricting orifices.

Boundary

Reactor coolant piping boundaries for SLR are included in the RCS SLR boundary drawings listed in Section 2.3.1, Reactor Coolant System.

System Intended Functions

Reactor coolant piping system intended functions for SLR are included in Section 2.3.1, Reactor Coolant System.

UFSAR References

Section 4.2.2

Components Subject to AMR

Table 2.3.1-1 lists the reactor coolant and connected piping component types that require AMR and their associated component intended functions.

Table 3.1.2-1 provides the results of the AMR.

2.3.1.1.2 Regenerative and Excess Letdown Heat Exchangers

Description

The regenerative and excess letdown heat exchangers are a part of CVCS. They are addressed in this section, however, because they are within the RCS pressure boundary.

The regenerative heat exchanger is of a multiple shell and U-tube design, each consisting of three heat exchangers interconnected in series by piping and mounted on a common support frame. The heat exchangers are designed to recover heat from the letdown stream by heating the charging stream, thus minimizing reactivity effects due to injection of cold water and minimizing thermal stress on the charging line penetrations in the reactor coolant loop piping. The letdown stream flows through the shell of the heat exchangers, and the charging stream flows through the tubes.

The excess letdown heat exchanger is of the U-tube design. Its function is to cool reactor coolant letdown flow equivalent to that portion of the nominal seal injection flow that enters the RCS through the labyrinth of the RCP seals. It may be used when the normal letdown path is temporarily out of service or for supplementing the maximum letdown during heat-up. The letdown is a four-pass flow through the tubes, while component cooling water (CCW) flow is a single pass through the shells.

Boundary

The regenerative and excess letdown heat exchanger boundaries for SLR are included in the RCS SLRBDs listed in Section 2.3.1, Reactor Coolant System. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

System Intended Functions

The regenerative and excess letdown heat exchanger system intended functions for SLR are included in the RCS intended functions in Section 2.3.1, Reactor Coolant System.

UFSAR References

Section 9.2

Components Subject to AMR

Table 2.3.1-1 lists the regenerative and excess letdown heat exchanger component types that require AMR and their associated component intended functions.

Table 3.1.2-1 provides the results of the AMR.

2.3.1.1.3 Reactor Coolant Pumps

Description

Each of the three reactor coolant loops for Turkey Point Units 3 and 4 contains a vertically mounted, single-stage centrifugal RCP. The RCPs provide the motive force for circulating the reactor coolant through the reactor core, piping, and steam generators. The RCPs used at Turkey Point are Westinghouse Model 93.

Each pump employs a controlled leakage seal assembly to restrict leakage along the pump shaft. The seal package is a multi-seal cartridge containing three identical stages in series. Only one stage is required to function to prevent excessive leakage from the RCS. Seal staging flow, designated control bleed-off, exits the RCP through lines to the CVCS seal return line that goes to the volume control tank. The flow that passes across the upper-seal stage, designated seal leak-off, is routed to the reactor coolant drain tank to minimize leakage of water and vapor into the containment atmosphere. To mitigate the effects caused by failure of all three stages, the seal package includes an Abeyance (shutdown) seal. The flow rates that result from various failure modes of the three stages vary and could result in flows that are not high enough to activate the Abeyance seal. With the RCP tripped, the Abeyance seal is designed to stop leakage from the upper, third-stage seal for an indefinite period, and RCP seal leakage is limited to flow through the control bleed-off seal return line.

Class 1 reactor coolant piping connected to the pumps is discussed in Section 2.3.1.1. The portions of the RCP rotating elements above the pump coupling, including the electric motor and the flywheel, are not subject to AMR in accordance with 10 CFR 54.21(a)(1)(i).

Boundary

The RCP boundaries for SLR are included in the RCS SLR boundary drawings listed in Section 2.3.1, Reactor Coolant System. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

System Intended Functions

The RCP system intended functions for SLR are included in Section 2.3.1, Reactor Coolant System.

UFSAR References

Section 4.2.2

Components Subject to AMR

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

Table 3.1.2-1 provides the results of the AMR.

Table 2.3.1-1
Reactor Coolant and Connected Piping
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Heat exchanger (channel head, shell and tubesheet)	Pressure boundary
Heat exchanger (tubes and coils)	Pressure boundary Heat transfer
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pressurizer relief tank	Structural integrity (attached)
Pump casing	Pressure boundary
Nozzles	Pressure boundary
Thermowell	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

2.3.1.2 Pressurizers

Description

The pressurizers are vertical cylindrical vessels containing electric heaters in the lower heads and a water spray nozzle in the upper heads. Since sources of heat in the RCS are interconnected by piping with no intervening isolation valves, pressure relief protection for the RCS is provided on the pressurizers. Overpressure protection consists of three code safety valves and two power-operated relief valves on each pressurizer. Piping attached to the pressurizer is Class 1 up to and including the second isolation valve (with the exception of the pressurizer code safety valves). The complete pressurizer is comprised of components, which include shells, nozzles, safe ends, manway cover, etc. Only those components that are passive in nature, long-lived, and directly support the accomplishment of an intended function require evaluation. The Turkey Point Units 3 and 4 pressurizers are identical with two exceptions: the manway closure that was modified on Unit 4 to an alternate configuration, and a heater well that was replaced on Unit 3. Note that the valves associated with the pressurizer are addressed in Section 2.3.1.1.1, Reactor Coolant Piping.

Boundary

The pressurizer boundaries for SLR are included in the RCS SLRBDs listed in Section 2.3.1, Reactor Coolant System. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

System Intended Functions

The pressurizer system intended functions for SLR are included in the RCS intended functions in Section 2.3.1, Reactor Coolant System.

UFSAR References

Section 4.2.2

Components Subject to AMR

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

Table 3.1.2-2 provides the results of the AMR.

Table 2.3.1-2
Pressurizers Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heater well components	Pressure boundary
Manway cover bolts	Pressure boundary
Pressurizer components: heads, shell, nozzles, manway cover	Pressure boundary
Safe ends, instrument nozzles, thermowells	Pressure boundary
Support skirt and flange	Structural support
Thermal sleeves[1]	Insulate (thermal)

Notes for Table 2.3.1-2

1. Thermal sleeves are not a part of the pressure boundary. However, thermal sleeves provide thermal shielding to minimize nozzle low-cycle thermal fatigue. Therefore, the thermal sleeves are considered to support the pressure boundary component intended function.

2.3.1.3 Reactor Vessels

Description

The reactor vessels consist of cylindrical vessel shells, lower-vessel heads, closure heads, nozzles, interior attachments, and associated pressure-retaining bolting. The vessels are fabricated of low-alloy steel with austenitic stainless steel cladding on internal surfaces exposed to the reactor coolant fluid. Instead of stainless steel cladding, the lower 15 ¾ inches of the lower shell is clad with nickel alloy. Four nickel alloy core support guides are welded to the lower shell course of the vessel in the nickel alloy clad region. Coolant flow for each reactor vessel enters through three inlet nozzles in a plane just below the vessel flange and above the core. The coolant flows downward, through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel, where it reverses direction, passes up through the core into the upper plenum, and then flows out of the vessel through three exit nozzles located on the same plane as the inlet nozzles.

The Turkey Point Units 3 and 4 reactor vessel closure heads (RVCHs) were replaced in 2004 and 2005, respectively, to address structural integrity of Alloy 600 closure head nozzles. The nozzles associated with the replacement heads are constructed of Alloy 690. Components replaced as part of the modification include:

- RVCH including control rod drive mechanism (CRDM) housing (inconel nozzle) and housing to CRDM adapter assembly
- RVCH vent nozzle
- CRDMs (complete assembly including pressure boundary material and non-pressure boundary material)
- Core exit thermocouple nozzle adapter (CETNA) assembly
- Reactor vessel level monitoring system (RVLMS) nozzle adapter assembly
- Spare CRDM nozzle cap (plug)
- RVCH O-ring clip
- Rod position indicator assemblies
- CRDM coil stacks

Bottom-mounted instrumentation (BMI) penetrates the reactor vessel lower-head domes. The 50 BMI flux thimble tubes and attached BMI guide tubes, flux thimble tubes, and seal table for each reactor vessel provide the capability of monitoring core flux distribution.

Boundary

The reactor vessel boundaries for SLR are included in the RCS SLRBDs listed in Section 2.3.1, Reactor Coolant System. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

System Intended Functions

The reactor vessel system intended functions for SLR are included in Section 2.3.1, Reactor Coolant System.

UFSAR References

Sections 3.0 and 4.2.2

Components Subject to AMR

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

Table 3.1.2-3 provides the results of the AMR.

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

Component Type	Component Intended Function(s)
BMI guide tubes	Pressure boundary Structural support
BMI flux thimble tubes	Pressure boundary Structural support
Bottom head dome	Pressure boundary Structural support
Bottom head torus	Pressure boundary Structural support
Closure head	Pressure boundary
Closure studs, nuts, washers	Pressure boundary
Core support lugs	Structural support
CRDM adapter	Pressure boundary
CRDM housing	Pressure boundary
CRDM latch housing	Pressure boundary
CRDM travel housing	Pressure boundary
Instrumentation tubes	Pressure boundary Structural support
Instrumentation tube safe ends	Pressure boundary Structural support
Intermediate shell	Pressure boundary
Lower shell	Pressure boundary
O-Ring leak monitor tubes	Pressure boundary
Primary nozzles (inlet)	Pressure boundary Structural support
Primary nozzles (outlet)	Pressure boundary Structural support

Table 2.3.1-3
Reactor Vessel
Components Subject to Aging Management Review (Continued)

Component Type	Component Intended Function(s)
Primary nozzle (safe ends)	Pressure boundary
Seal table	Structural support
Seal table fittings	Pressure boundary Structural support
Upper shell	Pressure boundary
Vent pipe extension	Pressure boundary
Vent pipe nozzle	Pressure boundary
Vessel flange	Pressure boundary Structural support

2.3.1.4 Reactor Vessel Internals

Description

The reactor vessel internals are designed to support, align, and guide the core components, and to support and guide in-core instrumentation. The reactor vessel internals consist of two basic assemblies for each reactor vessel: an upper-internals assembly that is removed during each refueling operation to obtain access to the reactor core; and a lower-internals assembly that can be removed, if desired, following a complete core offload.

The lower-internals assembly is supported in the vessel by resting on a ledge below the vessel head mating surface and is closely guided at the bottom by radial support/clevis assemblies. The upper-internals assembly is clamped at this same ledge by the reactor vessel head. The bottom of the upper-internals assembly is closely guided by the core-barrel alignment pins of the lower-internals assembly.

The lower internals comprise the core barrel, thermal shield, core-baffle assembly, lower-core plate, intermediate-diffuser plate, bottom-support casting, and supporting structures. The upper-internals assembly (upper-core support structure) is a rigid member composed of the top support plate and deep beam section, support columns, control rod guide tube assemblies, and the upper-core plate. Upon upper-internals assembly installation, the last three parts are physically located inside the core barrel.

Boundary

The reactor vessel internals boundaries for SLR are included in the RCS SLRBDs listed in Section 2.3.1, Reactor Coolant System. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

System Intended Functions

The reactor vessel internals intended functions for SLR are included in Section 2.3.1, Reactor Coolant System.

UFSAR References

Section 3.2.3

Components Subject to AMR

Table 2.3.1-4 lists the reactor vessel internals component types that require AMR and their associated component intended functions.

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

Component Type	Component Intended Function(s)
Lower Internals Assembly	
Lower core plate	Core support Flow distribution Guide instrumentation
Fuel alignment pins	Core support Flow distribution Guide instrumentation
Lower support forging	Core support Flow distribution Guide instrumentation
Lower support columns	Core support Guide instrumentation
Lower support column bolting	Core support Guide instrumentation
Radial keys	Core support
Diffuser plate	Flow distribution
Secondary core support	Core support Flow distribution Guide instrumentation
Bottom-mounted instrumentation column bodies	Guide instrumentation
Bottom-mounted instrumentation bases and extension bars	Guide instrumentation
Head cooling spray nozzles	Flow distribution
Interfacing Components	
Clevis insert	Core support
Upper core plate alignment pins	Core support Flow distribution
Internals hold-down spring	Core support
Head/vessel alignment pins	Guide rod control cluster assemblies (RCCAs)

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

Component Type	Component Intended Function(s)
Clevis insert bolting	Core support
Flux thimble tubes	Guide instrumentation
Lower Internals Assembly/Core Barrel Subassembly	
Core barrel flange	Core support Flow distribution
Core barrel outlet nozzles	Core support Flow distribution
Lower core barrel	Core support Flow distribution Shield vessel
Upper core barrel	Core support Flow distribution Shield vessel
Thermal shield	Shield vessel
Thermal shield flexures	Shield vessel
Lower Internals Assembly/Baffle-Former Subassembly	
Baffle and former assembly	Core support Flow distribution Shield vessel
Baffle-to-former bolts	Core support Flow distribution Shield vessel
Baffle edge bolts	Core support Flow distribution Shield vessel
Barrel-to-former bolts	Core support Flow distribution Shield vessel
Upper Internals Assembly	
Upper support plate	Core support Guide RCCAs

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

Component Type	Component Intended Function(s)
Upper support ring	Core support Guide RCCAs
Upper core plate	Core support Flow Distribution
Upper support column bases	Core support Guide RCCAs Guide instrumentation
Upper support columns	Core support Guide RCCAs Guide instrumentation
Upper support column bolting	Core support Guide RCCAs and support RCCAs
Upper instrumentation column (thermocouple support tubes)	Guide instrumentation
Guide Tube Assemblies (GTA)	
GTA lower flanges	Guide RCCAs
Guide cards	Guide RCCAs
GTA C-tubes	Guide RCCAs
GTA sheaths	Guide RCCAs
GTA support pins	Guide RCCAs
GTA bolting	Guide RCCAs

2.3.1.5 Steam Generators

Description

There are three identical steam generators installed in each unit. These steam generators are Westinghouse Model 44F. One steam generator is installed in each RCS loop. The steam generator is a vertical shell and tube heat exchanger, which transfers heat from a single-phase fluid at high temperature and pressure (the reactor coolant) in the primary side, to a two-phase (steam-water) mixture at a lower temperature and pressure in the shell side. The reactor coolant enters and exits the primary side of each steam generator through nozzles located in the lower hemispherical head. The RCS fluid flows through inverted U-tubes located within the lower head. The lower head is divided into inlet and outlet chambers by a vertical divider plate extending from the head to the tubesheet.

Feedwater is supplied to the steam generator from the main feedwater system at a temperature below its saturation temperature. Inside the steam generator, the feedwater is joined by the water recirculating from the moisture separators, producing a feed mixture for the tube bundle that is close to the saturation temperature. Therefore, only a small portion of the tube bundle, located just above the tubesheet, functions as a preheater to raise the fluid temperature to the saturation point. The major portion of the tube bundle operates in the heat transfer nucleate boiling region.

The Turkey Point Units 3 and 4 steam generators (with the exception of the channel heads and steam domes) were replaced in 1982 and 1983, respectively. The Turkey Point steam generator transition cone was cut to replace the bottom portion of the steam generator. There are now three circumferential welds in the transition cone. The lower shell to transition cone weld and the transition cone to upper shell are the original, manufacturer welds. The new circumferential weld is located just below the transition cone to upper shell weld. This weld is a field weld that was made during the steam generator replacement.

Boundary

The SLR boundaries are shown on the SLRBDs listed in Section 2.3.1, Reactor Coolant System.   There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

System Intended Functions

The steam generator system intended functions for SLR are included in Section 2.3.1, Reactor Coolant System.

UFSAR References

Section 4.2.2

Components Subject to AMR

Table 2.3.1-5 lists the steam generator component types that require AMR and their associated component intended functions.

Table 3.1.2-5 provides the results of the AMR.

Table 2.3.1-5
Steam Generators Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anti-vibration bars	Structural support
Blowdown piping	Structural integrity (attached)
Blowdown piping nozzles	Pressure boundary
Channel head with primary nozzles	Pressure boundary
Divider plate	Direct flow
Feedwater nozzle	Pressure boundary
Feedwater ring	Pressure boundary Structural integrity (attached)
Flow distribution baffle	Direct flow
J-tubes	Direct flow Structural integrity (attached)
Lower shell	Pressure boundary
Moisture separators	Structural integrity (attached)
Primary manway bolting	Pressure boundary
Primary manways (with disc insert)	Pressure boundary
Primary nozzle safe ends	Pressure boundary
Secondary closure bolting	Pressure boundary
Secondary closures: manway, access openings, inspection port and handholes	Pressure boundary
Secondary side shell penetrations	Pressure boundary
Seismic support lugs	Structural support
Steam flow limiter	Throttle
Steam generator tube plugs	Pressure boundary
Steam outlet nozzle	Pressure boundary
Support pads	Structural support
Transition cone	Pressure boundary
Tube bundle wrapper	Direct flow Structural support
Tube support plates	Structural support
Tubesheet	Pressure boundary
Upper shell and elliptical head	Pressure boundary
U-tubes	Pressure boundary Heat transfer

2.3.2 Engineered Safety Features

The following systems are addressed in this section:

- Emergency Containment Cooling (2.3.2.1)
- Containment Spray (2.3.2.2)
- Containment Isolation (2.3.2.3)
- Safety Injection (2.3.2.4)
- Residual Heat Removal (2.3.2.5)
- Containment Post Accident Monitoring and Control (2.3.2.6)

2.3.2.1 Emergency Containment Cooling

Description

The emergency containment cooling (ECC) systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units. ECC is designed to remove sufficient heat to maintain the containment below its structural design pressure and temperature during a loss-of-coolant accident (LOCA) or main steam line break (MSLB). In addition, the emergency fan cooling units continue to remove heat after these hypothetical accidents and reduce containment pressure to atmospheric. Heat removed from the containment is transferred to the component cooling water (CCW) system. The ECC, in each containment consists of three fan cooling units, each consisting of a motor, fan, cooling coils, housing, instrumentation and controls.

The cooling water requirements for the three emergency fan cooling units can be supplied by any one of the CCW pumps.

The emergency containment coolers are automatically initiated via the emergency diesel generator (EDG) sequencer by the reactor protection system/engineered safety features actuation system (RPS/ESFAS) on a safety injection (SI) signal. The ECC coolers are designed to perform at the rated heat removal capacity following initiation of a SI signal coincident with loss of offsite power (LOOP), within the minimum time assumed in the LOCA and MSLB analyses.

Boundary

The SLR boundaries are reflected in the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3057, Sheet 1

Turkey Point Unit 4
5614-M-3057, Sheet 1

With respect to mechanical boundaries, ECC only includes the ECC coolers. This includes the tube side of the ECC coolers' heat exchangers, but none of the closed treated water piping connected to the coolers.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) In conjunction with the containment spray system (CSS), prevent containment pressure and temperature from exceeding the values calculated in the containment LOCA and the MSLB accident analyses.

(2) Provide hydrogen mixing to preclude the accumulation of flammable concentrations in localized areas inside the containment during the long-term recovery from a LOCA.

(3) Without the CSS, maintain the containment atmosphere below the containment structural design pressure and temperature during a LOCA or MSLB.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) None

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

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

UFSAR References

Section 6.3
Section 14.3.4

Components Subject to AMR

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

Table 3.2.2-1 provides the results of the AMR.

Table 2.3.2-1
Emergency Containment Cooling
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Fan housing	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer

2.3.2.2 Containment Spray

Description

The containment spray systems (CSS) for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The CSS serves to mitigate the effects of a LOCA or MSLB inside containment. The CSS includes those components required to reduce containment temperatures and pressures to acceptable levels during LOCA or MSLB events. The system consists of two motor-driven, horizontal centrifugal pumps that each discharge through motor-operated valves, two spray headers and a series of nozzles (located near the top of the containment structure), and the necessary piping and valves. The system also utilizes the two residual heat removal (RHR) pumps, two residual heat exchangers and associated valves and piping of the SI system for the long-term recirculation phase of containment spray.

When the CSS is initiated the pumps take suction from the refueling water storage tank (RWST). The discharge valves open, and water from the pumps is forced through the spray nozzles in two lateral headers at the top of the containment.

The nozzles break the water into a spray of fine droplets. The surface area of the water, after it has been broken into droplets, is very large. The heat transfer from the air to this large water surface area gives the desired cooling effect to the containment atmosphere. The droplets also serve to absorb radioactive iodine from the air and to scrub out radioactive particulate material.

After the injection phase, coolant collected in the containment sump is recirculated via the RHR pumps to the RCS. A portion of the recirculation flow from the discharge of the RHR heat exchangers may be diverted to the suction of the spray pumps for use in the CSS. The CSS also functions long-term to add and recirculate buffered chemicals to neutralize the boric acid in the spilled coolant. This is accomplished with baskets containing sodium tetraborate (NaTB) located on the lower level of containment to dissolve the NaTB into the post-LOCA flood water.

Boundary

The SLR boundaries are reflected in the SLRBDs listed below. The only difference between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort is the NaTB baskets noted above and the elimination of the interface with the emergency containment filters, which were removed. Both of these changes were related to implementation of AST for Turkey Point (Reference 2.3.5.1).

Turkey Point Unit 3
5613-M-3062, Sheet 1
5613-M-3068, Sheet 1

Turkey Point Unit 4
5614-M-3062, Sheet 1
5614-M-3068, Sheet 1

With respect to mechanical boundaries, the suction piping upstream of the CS pumps' suction isolation valves is addressed with the RHR system. The RWST is the CSS's water source during the injection phase of an accident and is addressed with the SIS.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Following a LOCA or MSLB inside containment, spray borated water from the RWST into the containment. In conjunction with ECC, limit post-accident peak pressure and temperature within containment design limits.

(2) Be available during the long-term following a LOCA to recirculate cooled borated water from the sump via the RHR pumps and residual heat exchangers, as required to restore and maintain the containment conditions to near atmospheric pressure.

(3) Dissolve NaTB into post-LOCA flood water and raise the pH to 7.0 prior to the start of recirculation. Maintain the pH between 7.0 and 8.0 for long-term recirculation. Function for 30 days following a LOCA to recirculate and spray the buffered flood water to provide iodine retention.

(4) Remove elemental and particulate iodine from the containment atmosphere.

(5) Maintain post-LOCA sump pH such that re-evolution of iodine from the sump is inhibited.

(6) Maintain containment pressure boundary integrity including containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 6.4
Section 14.3.4

Components Subject to AMR

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

Table 3.2.2-2 provides the results of the AMR.

Table 2.3.2-2
Containment Spray Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
NaTB sump fluid pH control basket[1]	Structural support
Filter[2]	Pressure boundary Filter
Flow element	Pressure boundary Throttle
Heat exchanger (bands and clips)[3]	Structural support
Heat exchanger (coil shield)	Direct flow
Heat exchanger (shell)	Pressure boundary
Heat exchanger (coil)	Pressure boundary Heat transfer
Nozzle	Pressure boundary Spray
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.2-2

1. NaTB baskets are also included in Table 2.4.1-1 with AMR of the baskets included in Section 3.5.
2. Includes cyclone separator, Unit 3 only.
3. Component is internal to the CS pump seal water heat exchanger. The bands and clips provide support for the heat exchanger coil.

2.3.2.3 Containment Isolation

Description

The containment isolation systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

Containment isolation is an engineered safety feature (ESF) that provides for the closure and integrity of containment penetrations to prevent leakage of uncontrolled or unmonitored radioactive materials to the environment.

The pressure boundary (metallic) portions of electrical penetrations and miscellaneous penetrations (i.e., hatches) that are not associated with a process system are included in the structural screening described in Section 2.4.1.1.

The non-metallic and conductor portions of containment electrical penetrations are included in the electrical screening described in Section 2.5.

Note that all containment penetrations and associated containment isolation valves and passive components that ensure containment integrity, regardless of where they are described, require an AMR.

For mechanical systems that penetrate containment, the containment isolation function is addressed with those systems in their individual screening sections with the exception of containment purge and several stand-alone penetrations. These are addressed below.

The containment purge system on each unit is designed to purge the containment atmosphere of noble gases and radioactivity, and to allow personnel access during shutdown periods.

The containment purge system is independent of the containment and auxiliary building ventilation systems. The system consists of a common roughing filter, two purge supply fans and their respective discharge dampers, associated ductwork into and out of containment, four containment isolation valves (one inside containment and one outside per unit in both the supply and exhaust lines), a common roughing filter at the suction of the two purge exhaust fans, purge exhaust fan discharge dampers, and ductwork leading to the plant vent stack.

Both the supply and exhaust containment isolation valves are quick closing butterfly valves capable of closing in less than five seconds upon receipt of a containment isolation signal or high activity signal from the particulate or gaseous activity radiation monitors.

Debris screens are located inside containment inboard of the containment supply and exhaust purge valves. The debris screen and the pipe between the screens are seismically designed. The debris screens are designed to withstand the peak containment differential LOCA pressure. The debris screens will preclude material from blocking the containment isolation valves following a LOCA.

Prior to purging containment, radiation monitors are used to ensure the activity levels in containment are within the guidelines specified by 10 CFR 100, and while purging containment, discharges from the plant vent are continuously monitored.

The other stand-alone containment penetrations addressed in this section include:

- Integrated leak rate test connections
- Instrument air bleed
- Pressure test connections for access hatches
- Spare penetrations

<u>Boundary</u>

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3053, Sheet 1

Turkey Point Unit 4
5614-M-3053, Sheet 1

With respect to subsequent license renewal boundaries, the personnel access hatches and emergency escape hatches are addressed with the containment structure and internal structural components, Section 2.4.1. Containment isolation includes all piping, tubing, and valves connected to personnel access hatches and emergency escape hatches. For penetrations associated with containment isolation, the boundaries extend to the first isolation valve, blind flange, or pipe cap on both sides of the penetrations. The exceptions to this are the lines that include debris screens where the boundary extends past the isolation valve and up to the debris screen.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provides containment ventilation isolation to prevent the unrestricted release of radioactivity from the containment to the outside environment in the event of a LOCA without offsite power.

(2) Prevent or restrict the release of radioactive material from containment in the event of a fuel element rupture during refueling operations.

(3) Maintain containment pressure boundary integrity.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 6.6
Section 9.8

Components Subject to AMR

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

Table 3.2.2-3: provides the results of the AMR.

Table 2.3.2-3
Containment Isolation Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Filter housing	Pressure boundary
Filter element[1]	Filter
Piping	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.2-3

1. Containment purge debris screen.

2.3.2.4 Safety Injection

Description

The safety injection (SI) systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

SI for each unit consists of two motor-driven horizontal centrifugal pumps each discharging to a common header that feeds both Units 3 and 4. The SI header for each unit can feed the cold and hot legs of the RCS through the necessary piping and valves. Each unit is provided with a RWST. The RWST supply borated water to the SI pumps, RHR pumps, and containment spray (CS) pumps for core and containment cooling purposes. The SI pumps take suction from either the RWST during the post-accident injection phase, or from the RHR pump discharge during the post-accident recirculation phase. During normal operation, the RWST is aligned to the SI, CS and RHR pumps via two normally open, motor-operated isolation valves. These valves are closed during the recirculation phase of an accident.

Each SI pump is provided with one outboard seal cooler, one inboard seal cooler, and a thrust-bearing oil cooler. These coolers use CCW as a heat sink. Each SI pump has a minimum flow recirculation line to prevent overheating when the normal discharge flow paths are not available. The recirculation line from each pump connects to a common header, which discharges to the RWST. In addition, a full-flow capacity recirculation line is provided for testing the pumps.

The SI accumulators on each unit consist of three vessels pressurized with nitrogen and partially filled with borated water that discharge to the RCS cold legs through piping, motor operated valves and check valves. During normal operation, each accumulator is isolated from the RCS by two check valves in series. If the RCS pressure falls below the accumulator pressure, the check valves open, and borated water is forced into the RCS. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

The RWST also supply borated water to the reactor cavity and fuel transfer cavity for refueling operations, to the spent fuel pool (SFP) for makeup, and are the backup source of water to the charging pumps.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3062, Sheet 1
5613-M-3062, Sheet 2
5613-M-3064, Sheet 1

Turkey Point Unit 4
5614-M-3062, Sheet 1
5614-M-3062, Sheet 2
5614-M-3064, Sheet 1

With respect to mechanical evaluation boundaries, the 14 inch suction header to the RHR pumps' suction, as well as both normal and alternate 8 inch RHR discharge headers, are addressed with the RHR, Section 2.3.2.5. Additionally, piping and valves downstream of containment penetrations P-2 and P-11 up to the 10 inch accumulator injection header are addressed with RHR, Section 2.3.2.5. Isolation check valves 3-875A, 3-875B, 3-875C, 4-875A, 4-875B, and 4-875C, and associated downstream piping and components, are included with reactor coolant piping, Section 2.3.1.1.1. The 10 inch suction header to the CS pumps is addressed with CS, Section 2.3.2.2. The 2 and 4 inch headers to and from the chemical volume and control system (CVCS) and SFP are addressed in their respective sections, Section 2.3.3.4 and Section 2.3.3.3.

The subsequent license renewal boundaries associated with pneumatic valves that fail safe on loss of air are established at the valve actuator. These air valves and associated tubing/fittings support only an active venting function and pressure boundary integrity is not required.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide an alternate source of borated water for reactivity control during abnormal conditions when the boric acid tanks and associated equipment are not available.

(2) Provide emergency core cooling and reactivity control for the following accident conditions:

a. A steam generator tube failure.

b. A rupture of a steam pipe or spurious relief valve lifting in the secondary system.

c. LOCA, including rupture of a control rod mechanism.

d. A feedwater line break (FWLB).

(3) The RWST, a subsystem of the SI system, shall provide the borated water needed to supply the SI system pumps, RHR pumps, and the CS pumps during the injection phase immediately following a LOCA (or secondary accident causing pressurization of containment)

(4) In conjunction with the RHRS, cool and recirculate the water that is collected in the containment recirculation sumps, returning it to the RCS to provide long-term core cooling.

(5) Maintain containment pressure boundary integrity including containment isolation.

(6) Provide a source of makeup to the SFPs in the unlikely event that SFP cooling is lost and pool boiling occurs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 6.2

Components Subject to AMR

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

Table 3.2.2-4 provides the results of the AMR.

Table 2.3.2-4
Safety Injection Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Flow element	Pressure boundary
Heat exchanger[1]	Pressure boundary Heat transfer
Heat exchanger (bands and clips)[2]	Structural support
Heat exchanger (coil shield)	Direct flow
Heat exchanger (shell)	Pressure boundary
Heat exchanger (coil)	Pressure boundary Heat transfer
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Tank	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

<u>Notes for Table 2.3.2-4</u>

1. SI pump thrust-bearing coolers.
2. Component is internal to the SI pump seal water heat exchanger. The bands and clips provide support for the heat exchanger coil.

2.3.2.5 Residual Heat Removal

<u>Description</u>

The residual heat removal systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

During normal plant operation, the residual heat removal (RHR) system is maintained in stand-by mode, ready to provide safety injection following automatic actuation by a safety injection signal.

During a LOCA, the RHR system takes suction from either the RWST or the containment recirculation sumps to deliver borated water to the RCS. In conjunction with the SI system, the RHR system provides emergency core cooling to prevent damage to the reactor core.

Along with providing emergency core cooling, the RHR system is also used during a LOCA to deliver water from the containment recirculation sumps and provide it to the CS system. Along with the CS system, the RHR system provides heat removal from the reactor core.

The primary system function during non-accident conditions and following the recovery from various plant transients is to remove decay and sensible heat from the core during cooldown and refueling operations. A secondary function of the RHR system is to transfer refueling water between the RWST and the refueling canal as required for refueling operations and to direct a portion of the flow to the chemical and volume control system (CVCS) for purification and clean-up.

The RHR system consists of two independent, redundant trains, A and B. Each train consists of a pump, heat exchanger, attendant instrumentation, interconnecting piping between the RCS loops, containment recirculation sumps, and the SI, chemical and volume control (CVC), and CS systems. Either train of RHR is capable of performing the RHR system's intended safety function.

<u>Boundary</u>

SLR boundaries are reflected on the SLR boundary drawings listed below.

Turkey Point Unit 3
5613-M-3050
5613-M-3064

Turkey Point Unit 4
5614-M-3050
5614-M-3064

With respect to subsequent license renewal mechanical boundaries, the piping and valves downstream of valves 3/4-876A, B, C, D, and E are addressed with SI, Section 2.3.2.4. The only exception is valve 3/4-941V, which is included with RHR. All components within the reactor coolant pressure boundary are included in Section 2.3.1.1, Reactor Coolant and Connected Piping. The RHRS also interfaces with component cooling water, primary sampling system, plant air, and the chemical and volume control system. The piping and associated valves in these systems are addressed in their respective sections.

With regard to differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort, various vent valves were added to the Unit 3 and 4 RHRS as a result of NRC GL 2008-01. Additionally, containment sump strainers are part of the RHR and are screened with the other RHR components. Further description of the sump strainers is provided in UFSAR Section 6.2.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide the low-head safety injection part of the emergency core cooling function during a LOCA.

(2) In conjunction with the SIS, cool and recirculate the water that is collected in the containment recirculation sumps and return it to the RCS, SIS, and CSS to maintain reactor core and containment cooling functions during the cold leg recirculation phase following a LOCA.

(3) In conjunction with the SIS, provide safety injection flow to the RCS hot legs during the long-term recirculation phase of a LOCA.

(4) Provide RCS mixing during operations involving a change in boron concentration in the RCS when the reactor coolant pumps are not in operation. This function assures a homogeneous boron concentration throughout the RCS during either a boration or dilution event.

(5) Maintain containment pressure boundary integrity including containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection and for the EQ Program.

UFSAR References

Section 6.2
Section 9.3

Components Subject to AMR

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

Table 3.2.2-5 provides the results of the AMR.

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

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Expansion joint	Pressure boundary Expansion/separation
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubesheet)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing	Pressure boundary
Strainer body[1]	Pressure boundary
Strainer element[1]	Filter
Thermowell	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.2-5

1. Containment sump strainers.

2.3.2.6 Containment Post-Accident Monitoring and Control

Description

The containment post-accident monitoring and control systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

- The mechanical portions of containment post-accident monitoring and control include the following subsystems:
- Post-accident hydrogen monitoring
- Containment pressure monitoring
- Post-accident sampling
- Post-accident hydrogen control
- Containment air particulate and gas monitoring

This section addresses the mechanical components and SCs that are required to support the system intended functions of these subsystems.

Post-accident hydrogen monitoring provides indication of the hydrogen gas concentration in the containment atmosphere following a LOCA. Two completely independent trains are provided to monitor for free gaseous hydrogen. The trains are closed loop, returning the analyzed sample to containment. Sample flow is educted from containment and pumped back to containment by diaphragm pumps, one located inside each analyzer housing. The mechanical portions of post-accident hydrogen monitoring provide a flow path from the containment to the hydrogen monitors and then back to containment.

Containment pressure monitoring consists of redundant containment pressure signals that are provided to isolate the containment and initiate several reactor safeguard actions. The mechanical portions of containment pressure monitoring provide sensing lines from the containment to the containment pressure monitors.

The only mechanical portion of post-accident sampling in the scope of license renewal is the sample cooler because it forms a part of the CCW pressure boundary.

Containment air particulate and gas monitoring measures radioactivity in the containment air. The mechanical portions of containment air particulate and gas monitoring provide a flow path from the containment to the monitors and then back to the containment.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Common:
5610-M-3094, Sheet 1
5610-M-3094, Sheet 2
5610-M-3094, Sheet 3

Turkey Point Unit 3:
5613-M-3094, Sheet 1

Turkey Point Unit 4:
5614-M-3094, Sheet 1

With respect to subsequent license renewal mechanical boundaries, containment post-accident monitoring and control includes the pass sample cooler and the O_2 pure gas cylinders. Gas lines from the O_2 pure gas cylinders are included through the system's H_2 monitors and up to the containment penetrations and/or their respective isolation and vent valves as shown on the SLRBD. Additional lines are included in support of required instrumentation and are also shown on the SLRBD.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide pressure input to initiate containment isolation, SI and actuation of other reactor safeguards systems upon receipt of high and high/high containment pressure following a postulated accident.

(2) Provide control of radioactive releases by isolating the containment purge and instrument air bleed lines in any abnormal event that results in excessive radiation releases to the containment. Additionally, provide a signal to isolate the control room ventilation system (CRVS) and thus prevent the potential ingress of radioactivity into the control room.

(3) Maintain containment pressure boundary integrity including containment isolation.

(4) Provide pressure boundary integrity for CCW (sample cooler).

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 7.5
Section 9.3
Section 9.12
Section 9.13
Section 9.14
Section 11.2.3

Components Subject to AMR

Table 2.3.2-6 lists the containment post-accident monitoring and control component types that require AMR and their associated component intended functions.

Table 3.2.2-6 provides the results of the AMR.

Table 2.3.2-6
Containment Post-Accident Monitoring and Control
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Heat exchanger (head/tubesheet)	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)[1]	Pressure boundary
Piping	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.2-6

1. Heat transfer is not an SLR component intended function for this component.

2.3.3 Auxiliary Systems

The following systems are addressed in this section:

- Intake Cooling Water (2.3.3.1)
- Component Cooling Water (2.3.3.2)
- Spent Fuel Pool Cooling (2.3.3.3)
- Chemical and Volume Control (2.3.3.4)
- Primary Water Makeup (2.3.3.5)
- Primary Sampling (2.3.3.6)
- Secondary Sampling (2.3.3.7)
- Waste Disposal (2.3.3.8)
- Plant Air (2.3.3.9)
- Normal Containment Ventilation (2.3.3.10)
- Plant Ventilation (2.3.3.11)
- Fire Protection (2.3.3.12)
- Emergency Diesel Generator Cooling Water (2.3.3.13)
- Emergency Diesel Generator Air (2.3.3.14)
- Emergency Diesel Generator Fuel and Lubrication Oil (2.3.3.15)
- Auxiliary Systems in the Scope of 10 CFR 54.4(a)(2) for Spatial Interactions (2.3.3.16)

2.3.3.1 Intake Cooling Water

Description

The intake cooling water (ICW) systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

Each ICW system consists of three ICW pumps, two redundant piping headers, two ICW basket strainers upstream of the CCW heat exchangers, two ICW basket strainers upstream of the turbine plant cooling water (TPCW) heat exchangers, and associated valves and fittings.

The three ICW pumps located in the intake structure pump water from the cooling canals through two redundant 100% supply headers (A and B), to the tube side of three CCW heat exchangers and two TPCW heat exchangers to the plant’s discharge canal. Note that the CCW heat exchangers are screened with the CCW system (Section 2.3.3.2).

The heat that is absorbed by CCW from primary system components, located in the auxiliary building and the containment building, is transferred from that system to ICW. The resulting warmer ICW water is carried to the plant's discharge canal.

Under non-accident conditions, the heat that is absorbed by the TPCW system from secondary system components, located in the turbine building area of the plant, is transferred from that system to the ICW system. The resulting warmer ICW water is carried to the plant's discharge canal. Pneumatically operated valves automatically close on a SI signal to isolate ICW flow to the TPCW heat exchangers. This function assures adequate ICW flow to the CCW heat exchangers during accident conditions.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. The boundaries have been extended beyond the boundaries identified in the original Turkey Point license renewal effort to support changes associated with NFPA 805.

Turkey Point Unit 3
5613-M-3019, Sheet 1
5613-M-3019, Sheet 2

Turkey Point Unit 4
5614-M-3019, Sheet 1
5614-M-3019, Sheet 2

The subsequent license renewal boundaries of the ICW system begin with the ICW pumps at the intake structure. For the ICW piping and components that are associated with heat removal from the CCW heat exchangers, the subsequent license renewal boundary ends at the discharge structure. For the ICW piping and components associated with heat removal from the TPCW heat exchangers, the safety-related pressure boundary ends at the downstream side of POV-*-4882, POV-*-4883, *-50-315, and *-50-335. The nonsafety-related piping and the TPCW heat exchangers provide seismic support/anchorage for the upstream safety-related portion of the system. For NFPA 805, this piping must maintain a pressure boundary downstream to valve *-50-401 to provide isolation of ICW in the event of spurious operation of POV-*-4882 or POV-*-4883, and thus these piping and components are included in the scope of subsequent license renewal.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Remove the heat load from the CCW system during DBA conditions to support both reactor heat removal and containment heat removal requirements.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) The ICW system shall remove the heat load from the CCW system to support the spent fuel cooling requirements.

(2) The ICW system shall remove the heat load from the CCW system during refueling operation (Mode 6) to support the core decay heat removal requirements.

(3) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

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

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

UFSAR References

Section 9.6.2

Components Subject to AMR

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

Table 3.3.2-1 provides the results of the AMR.

Table 2.3.3-1
Intake Cooling Water
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Expansion joint	Pressure boundary
Flow element	Pressure boundary Throttle
Heat exchanger (channel head)[1]	Pressure boundary
Heat exchanger (shell)[1]	Structural integrity (attached)
Heat exchanger (tubes)[1,2]	Pressure boundary
Heat exchanger (tubesheet)[1]	Pressure boundary
Nozzle	Pressure boundary
Orifice	Pressure boundary
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Strainer body	Pressure boundary
Strainer element	Filter
Thermowell	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.3-1

1. These are the TPCW heat exchanger components. The CCW heat exchangers are addressed in Section 2.3.3.2.
2. Heat transfer is not an SLR component intended function for this component.

2.3.3.2 Component Cooling Water

Description

The component cooling water (CCW) systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The CCWS is a closed-loop cooling water system that removes heat from safety-related and nonsafety-related components located in the auxiliary building and containment building. The CCWS is the heat sink for the RHRS, the CVCS, the ECCS, the SFP cooling system (SFPCS) and various RCS components. The closed loop design permits use of a corrosion inhibitor to protect the internal surfaces of the CCWS from corrosion. The CCWS consists of three CCW pumps, three CCW heat exchangers, a CCW surge tank, a CCW head tank, a CCW chemical addition tank, two redundant cooling loops (designated train A and train B), and various instrumentation and controls.

The CCW pumps circulate component cooling water through heat exchangers and coolers that are associated with other systems in order to transfer heat from those systems into the CCWS. CCW heat exchangers transfer heat from the CCWS to the ICWS as ICW (raw water) flows through the CCW heat exchangers tubes.

The CCW head tank is connected to, and installed above, the CCW surge tank. The CCW head tank is used to monitor in-leakage from other systems and out-leakage from the CCWS. The surge tank is water-solid during power operations, but it can be drained to provide CCWS-level indication during refueling operations. The CCW head tank provides sufficient static head in the ECC coolers to prevent the possibility of post-LOCA steam void formation in those coolers.

The safety-related heat loads include the RHR heat exchangers and RHR pump seal coolers, the SI oil coolers and seal water coolers, the SFP heat exchanger, the CS pump seal coolers, and the ECC coolers.

Boundary

SLR boundaries are reflected on the SLRBDs listed below. The only difference between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort is the addition of a second SFP cooling heat exchanger on both units and CCW connection to a supplemental cooling (chilled water) system on Unit 3.

Turkey Point Unit 3
5613-M-3030, Sheet 1
5613-M-3030, Sheet 2
5613-M-3030, Sheet 3
5613-M-3030, Sheet 4
5613-M-3030, Sheet 5
5613-M-3030, Sheet 6

Turkey Point Unit 4
5614-M-3030, Sheet 1
5614-M-3030, Sheet 2
5614-M-3030, Sheet 3
5614-M-3030, Sheet 4
5614-M-3030, Sheet 5

With respect to subsequent license renewal mechanical boundaries, CCW includes all safety-related CCW piping and components, not including heat exchangers from other major systems. For example, CCW includes all piping up to RHR heat exchanger 3E206A and all piping containing CCW that is leaving the heat exchanger. All heat exchanger shell and tubing management is done under the system to which the heat exchanger belongs, which in this case is the RHRS.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide cooling water to safety-related equipment during DBEs to support reactor decay heat removal, containment heat removal, and safe shutdown requirements.

(2) Automatically isolate non-essential heat loads in containment following an accident (LOCA or MSLB) inside containment. Automatic isolation shall be initiated by measurement of abnormal pressure inside the containment structure.

(3) Automatically isolate the cooling water to the RCP thermal barriers upon detection thermal barrier failure in order to prevent potential radiation release outside the containment.

(4) Provide cooling to all four SI pumps from either unit.

(5) Maintain containment pressure integrity including containment isolation and piping inside containment closed to the containment atmosphere.

(6) Provide cooling water to the spent fuel pool cooling (SFPC) system to support spent fuel pool cooling requirements.

(7) Provide cooling water to equipment required to operate during refueling operations (Modes 5 and 6) to support core decay heat removal requirements.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.3

Components Subject to AMR

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

Table 3.3.2-2 provides the results of the AMR.

Table 2.3.3-2
Component Cooling Water
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Pressure boundary
Filter element	Filter
Filter housing	Pressure boundary
Flow element[1]	Pressure boundary
Heat exchanger[2]	Pressure boundary
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Heat exchanger (tubesheet)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Tank	Pressure boundary
Thermowell	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.3-2

1. Throttle is not an SLR component intended function for this component.
2. Heat transfer is not an SLR component intended function (miscellaneous nonsafety-related auxiliary equipment heat exchangers).

2.3.3.3 Spent Fuel Pool Cooling

Description

The SFPC system for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The spent fuel pools for both units are located in the auxiliary building as part of spent fuel storage and handling, and provide wet storage and safe handling of new and used fuel. The SFPC system removes decay heat generated by the spent fuel assemblies. The coolant (borated water) transfers heat to the CCWS and provides radiation protection.

The SFPC system on each unit is a closed-loop system consisting of three subsystems. The system functions to cool, purify, and skim the pool. The SFPC system functions through three loops: cooling loop, purification loop, and skimmer loop. The system also maintains water inventory in the SFPs.

The SFPC cooling loop circulates water from the SFP through the SFPC heat exchangers, and back to the SFP. The system consists of two SFPC pumps, one emergency pump, two heat exchangers, and associated piping, valves, controls and instrumentation.

The SFPC purification loop maintains the pools' clarity and removes fission products and other contaminants. The SFPC purification loop services both the RWST and the SFP. The purification loop consists of one demineralizer, one RWST purification pump, three spent fuel pool filters, piping, valves, controls, and instrumentation. When the SFP water is being purified, water from the SFPC pump flows through the demineralizer, two of the three filters and then returns to the SFPC cooling loop. During this process, the RWST flow path is isolated. The process of purifying the RWST water isolates the SFP flow path. Water from the RWST purification pump flows through the SFPC demineralizer, two of the three filters and returns water to the RWST.

The third water flow pathway is the skimmer loop. The skimmer loop is nonsafety-related. The skimmer loop addresses water clarity by removing dust and debris from the SFP water surface. The system consists of two skimmer pump suction heads, one skimmer pump basket strainer, one skimmer pump, three skimmer pump filters, piping, valves, controls and instrumentation.

There are four sources of makeup water available to replenish inventory losses in the SFP. The demineralized water system is the normal makeup supply. Alternate supply sources are the RWST (borated source), fire water system, and the primary water storage tank (PWST).

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. The boundaries have been modified from the boundaries identified in the original Turkey Point license renewal effort due to the installation of an additional heat exchanger in each SFPC system.

Turkey Point Unit 3
5613-M-3033 Sheet 1

Turkey Point Unit 4
5614-M-3033 Sheet 1

The subsequent license renewal boundary of this system is based on its functions and includes the cooling loop, purification loops, and the associated interfaces with the SFP and RWST. The components that make up the SFP skimmer loops are within the scope of license renewal because of their potential to affect safety-related SFPC equipment due to spatial interaction.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Remove decay heat from the fuel assemblies.

(2) Maintain cooling system pressure boundary when the purification loop is in service.

(3) Provide SFP inventory control when the reactor cavity is drained, and the SFP is open to the fuel transfer canal.

Nonsafety-related components that could affect safety related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.5

Components Subject to AMR

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

Table 3.3.2-3 provides the results of the age management review.

Table 2.3.3-3
Spent Fuel Pool Cooling
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Filter housing[2]	Pressure boundary Leakage boundary (spatial)[1]
Flow element[3]	Pressure boundary
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Heat exchanger (tubesheet)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary Leakage boundary (spatial)[1]
Tank	Pressure boundary
Thermowell	Pressure boundary
Tubing	Pressure boundary Leakage boundary (spatial)[1]
Valve body	Pressure boundary Leakage boundary (spatial)[1]
Vortex diffuser	Direct flow

Notes for Table 2.3.3-3

1. See Section 2.3.3.16 for additional information regarding components with an intended function of leakage boundary (spatial).
2. Filter elements are replaced periodically.
3. Throttle is not an SLR component intended function for this component.

2.3.3.4 Chemical and Volume Control

Description

The CVCS for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The CVCS provides a continuous feed and bleed for the RCS to maintain proper water level and to adjust boron concentration.

The CVCS is a major support system for the RCS. The CVCS will process (60 gpm during normal operations) reactor coolant through mixed-bed demineralizers to maintain coolant purity. The CVCS will maintain a continuous letdown and charging flow for RCS inventory control and RCP shaft seals.

The CVCS performs the following tasks:

- Purify the reactor coolant using filters and demineralizers.
- Regulate the reactor coolant boric acid concentration.
- Maintain reactor coolant chemistry by adding corrosion inhibiting chemicals.
- Maintain and provide borated water for emergency core cooling.
- Degasifying reactor coolant.
- Fill and hydrostatically test the RCS.
- Provide makeup from the holdup tanks.
- Transfer boric acid solution from the boric acid batching tank and storage tanks to the charging pumps using the boric acid transfer pumps.

The CVCS includes boron addition and supply, which provides makeup, transfers boric acid solution, and maintains reactor water purity. Some components of boron addition and supply are common to Turkey Point Units 3 and 4.

Insulation is not within the scope of SLR for CVCS because the systems do not contain boric acid solutions at concentrations that require heat tracing, tank heaters, and/or insulation to prevent precipitation.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. The boundaries have been modified from the boundaries identified in the original Turkey Point license renewal effort due to the elimination of the need for the CVCS holdup tanks for fire protection.

Common
5610-M-3046, Sheet 1
5610-M-3046, Sheet 2
5610-M-3046, Sheet 3
5610-M-3046, Sheet 4

Turkey Point Unit 3
5613-M-3041, Sheet 1
5613-M-3041, Sheet 2
5613-M-3046, Sheet 1
5613-M-3046, Sheet 2
5613-M-3047, Sheet 1
5613-M-3047, Sheet 2
5613-M-3047, Sheet 3

Turkey Point Unit 4
5614-M-3041, Sheet 1
5614-M-3041, Sheet 2
5614-M-3046, Sheet 1
5614-M-3046, Sheet 2
5614-M-3047, Sheet 1
5614-M-3047, Sheet 2
5614-M-3047, Sheet 3

The CVCS interfaces with multiple systems with subsequent license renewal boundaries that can be defined by the following locations. The 2 inch RHR heat exchanger outlet header upstream of HCV-3-142 is addressed with RHR. The excess letdown upstream of valve *-308, 3 inch charging line headers downstream of *-312A (B), auxiliary spray header downstream of *-313, and letdown upstream of *-3090 are included with reactor coolant piping. The 2” line downstream of valve *-802C is addressed with SI. The ¾ inch sampling system interface from the letdown line downstream of *-205B is included with primary sampling. The ¾ inch vent header downstream of *-259B is addressed by waste disposal. Boundary valves *-262 are included within CVCS as well as various interface valves with the waste disposal system shown on the SLRBD.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Borate the RCS at a rate sufficient to match the maximum xenon burnup rate.

(2) Borate the RCS at a rate sufficient to match the maximum xenon decay rate following an extended shutdown from power.

(3) Serve as an alternate reactor shutdown system in place of control rods in the unlikely event that the rod control system has malfunctioned.

(4) Provide blended boric acid of required concentration and total flow rate to the RWST, SFP, and volume control tank.

(5) Maintain containment pressure boundary integrity including containment isolation.

(6) Various components form part of the RCS pressure boundary.

(7) Preheat charging supply to the RCS.

(8) Cool letdown leaving the RCS.

(9) Provide injection water to the RCP shaft seals.

(10) Maintain and control RCS pressurizer level.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.2

Components Subject to AMR

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

Table 3.3.2-4 provides the results of the AMR.

Table 2.3.3-4
Chemical and Volume Control
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Filter housing[2]	Pressure boundary
Flow element	Pressure boundary Throttle Leakage boundary (spatial)[1]
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Heat exchanger (tubesheet)	Pressure boundary
Orifice	Pressure boundary Throttle Leakage boundary (spatial)[1]
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Pressure boundary Structural integrity (attached) Leakage boundary (spatial)[1]
Pump casing	Pressure boundary
Tank	Pressure boundary
Thermowell	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.3-4

1. See Section 2.3.3.16 for additional information regarding components with an intended function of leakage boundary (spatial).
2. Filter elements are replaced periodically.

2.3.3.5 Primary Water Makeup

Description

The primary water makeup (PWM) systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

Each unit's PWM system consists of:

- One primary water storage tank (PWST)
- Two primary water pumps
- One gas transfer membrane (GTM) deaerator skid
- Associated piping, valves, and instrumentation

The PWM system distributes water from the PWST to multiple systems in the auxiliary building, containment building, and radwaste building. Primary water is unborated, deaerated, demineralized water suitable for use in the RCS. Boric acid may be added to primary water in the desired concentration before it is used as reactor coolant. Primary water has a lower oxygen content than demineralized water, but is otherwise the same.

The PWM system is most frequently used to supply primary water to the blender station for boron concentration control. Primary water is also used for CCW makeup, SFP makeup, pressurizer relief tank (PRT) sprays, boric acid batch tank makeup, boric acid pump flushes, CVCS chemical pot flushes, CVCS demineralizer resin fill and flush evolutions, SFP demineralizer resin fill and flush evolutions, spent resin storage tank makeup, spent resin header flushes, and radwaste operations.

PMW is generally classified as nonsafety-related. However, a portion of the system is safety-related where it passes through containment penetrations.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. The boundaries have been modified from the boundaries identified in the original Turkey Point license renewal effort due to modifications which eliminated the need for PWM to the RCP standpipes.

Turkey Point Common
5610-M-3020, Sheet 1

Turkey Point Unit 3
5613-M-3020, Sheet 1
5613-M-3020, Sheet 2

Turkey Point Unit 4
5614-M-3020, Sheet 1
5614-M-3020, Sheet 2

The subsequent license renewal boundaries associated with PWM include components and piping between check valve *-10-567 and *-10-582 located at penetration P-47. Primary water also includes structural integrity attached items starting at the buried piping coming from the water treatment plant, and includes piping up to check valve *-10-567 and various other check valves and isolation valves. Portions of this piping are also required for leakage boundary, and are included up to the check and isolation valves leading to the letdown demineralizers, CVCS, and the boric acid blender. These boundaries are shown in detail on the SLRBD.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure integrity including containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

<u>UFSAR References</u>

Section 9.6.2

<u>Components Subject to AMR</u>

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

Table 3.3.2-5 provides the results of the AMR.

Table 2.3.3-5
Primary Water Makeup Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Flow element	Leakage boundary (spatial)[1]
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Structural integrity (attached)
Tubing	Pressure boundary
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.3-5

1. See Section 2.3.3.16 for additional information regarding components with an intended function of leakage boundary (spatial).

2.3.3.6 Primary Sampling

Description

The primary sampling systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The primary sampling system enables plant personnel to evaluate fluid chemistry in the RCS, the RHR, the CVCS, and the SIS (accumulators) by providing samples of fluid in these systems for chemical analysis. Analysis of the samples reveals the concentration of boron, chloride, fluoride, hydrogen, oxygen, suspended solids, chemical additives, and fission gas in the systems, as well as the level of fission and corrosion product radioactivity.

Reactor coolant hot leg liquid, accumulator liquid, pressurizer liquid and pressurizer steam samples originating inside the containment flow through separate sample lines to the sampling room. The samples pass through the containment to the auxiliary building, and into the sampling room, where they are cooled by the sample heat exchangers (except accumulator samples).

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3036, Sheet 1

Turkey Point Unit 4
5614-M-3036, Sheet 1

The subsequent license renewal boundaries of the primary sampling system determined to be within the scope of the subsequent license renewal were established at the first isolation valve on the connection to systems from which samples are taken, at the first isolation valve outside containment for lines penetrating containment, and at the connections between the instrument air system and components using instrument air for their operation. Note that there are no sample system valves that require instrument air to perform their subsequent license renewal intended function.

The sample heat exchangers (3/4E209A, B and C) are identified within the scope of subsequent license renewal for the primary sampling system. The intended function of these heat exchangers is to maintain CCW pressure boundary. They do not perform a safety-related heat transfer function and are not installed in any safety-related portion of the primary sampling system. The tube sides of these heat exchangers are isolated on the inlet and outlet by normally closed 3/8-inch, stainless steel globe valves. On the CCW side, CCW flow is established during plant startup and maintained continuously during normal plant operation. While the shell-side of these heat exchangers function as the CCW pressure boundary, the tube-side is normally isolated from the respective sample point except when a sample is being drawn. Thus, the breach of tube integrity under “normal” conditions (i.e., sample tube side isolated) would have no impact on the CCW system during normal operations. Likewise, a breach of tube integrity when a sample cooler is placed in service (i.e., sample being drawn) would result in leakage of reactor coolant fluid (liquid or steam, as applicable) into the CCW system with no loss of CCW function. Based on this discussion, only the shell and cover of the sample coolers are considered in the scope of subsequent license renewal. The sample cooler tubes are not considered within the scope of subsequent license renewal.

The subsequent license renewal boundaries associated with pneumatic valves that fail safe on loss of air are established at the valve actuator. These air valves and associated tubing/fittings support only an active venting function and pressure boundary integrity is not required.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure integrity including containment isolation.

(2) Provide pressure boundary integrity at the sample connections to RCS, RHR, CVCS, and SI accumulators.

(3) Provide pressure boundary integrity for CCW (sample heat exchangers).

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection, for the EQ Program and for SBO.

<u>UFSAR References</u>

Section 9.4.1

Components Subject to AMR

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

Table 3.3.2-6 provides the results of the AMR.

Table 2.3.3-6
Primary Sampling Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Heat exchanger (shell and cover only)[2]	Pressure boundary
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached) Leakage boundary (spatial)[1]
Tubing	Pressure boundary Leakage boundary (spatial)[1]
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.3-6

1. See Section 2.3.3.16 for additional information regarding components with an intended function of leakage boundary (spatial).
2. Heat transfer is not an SLR component intended function for this component.

2.3.3.7 Secondary Sampling

Description

The secondary sampling systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The secondary sampling system is designed to permit remote sampling of fluids of secondary plant systems. The system is designed to be manually operated. A portion of this system associated with the sampling of the steam generator blowdown (SGBD) system is located inside the containment. Other portions of the system are located in the turbine building and in the auxiliary building. The system is composed of piping/tubing, valves and the instrumentation required for its operation. The system tubing and valves are connected to sections of piping of the systems from which the samples are taken.

The sample system enables plant personnel to evaluate fluid chemistry in the feedwater, condensate/condenser hot well, SGBD, main steam and heater drain systems including the fluid from the moisture separator reheater (MSR) drains by providing samples of fluid in these systems for chemical analysis.

Radiation monitors are provided on SGBD sampling lines for continuously monitoring the radiation levels in lines to the discharge canal. These radiation monitors provide alarm in the control room and an isolation signal for the SGBD system when the predetermined radiation level limits are exceeded.

Isolation valves are provided outside containment on the SGBD sample lines leaving the containment. These isolation valves will close upon actuation of the containment isolation signal or auto start of the auxiliary feedwater (AFW) pumps.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3032, Sheet 1
5613-M-3032, Sheet 2
5613-M-3032, Sheet 3
5613-M-3032, Sheet 5
5613-M-3032, Sheet 6
5613-M-3032, Sheet 7

Turkey Point Unit 4
5614-M-3032, Sheet 1

5614-M-3032, Sheet 2
5614-M-3032, Sheet 3
5614-M-3032, Sheet 5
5614-M-3032, Sheet 6
5614-M-3032, Sheet 7

Apart from its pressure boundary interface with safety-related systems and its containment isolation pressure boundary, the remainder of secondary sampling is not within the scope of subsequent license renewal.

Three safety-related sample coolers (3/4-SC-1432, -1433, and -1434) are identified within the scope of subsequent license renewal for secondary sampling. The intended function of these sample coolers is to maintain the pressure boundary of the main steam system and of the steam supply to the auxiliary feed pump turbines.

The subsequent license renewal boundaries associated with pneumatic valves that fail safe on loss of air are established at the valve actuator. These air valves and associated tubing/fittings support only an active venting function and pressure boundary integrity is not required.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure integrity including containment isolation.

(2) Provide pressure boundary integrity at the sample connections to safety-related portions of the main steam and SGBD systems.

(3) Provide restrictions for the main stream flow through the sample system to limit the radioactivity release from this system to acceptable levels during a steam generator tube rupture (SGTR) accident and to prevent detrimental effect on the operation of the AFW pump turbines.

Nonsafety-related components which could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

(2) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection, for ATWS and for SBO.

UFSAR References

Section 10.2

Components Subject to AMR

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

Table 3.3.2-7 provides the results of the AMR.

Table 2.3.3-7
Secondary Sampling Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Heat exchanger (tubes)[1]	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.3-7

1. Heat transfer is not an SLR component intended function for this component.

2.3.3.8 Waste Disposal

Description

The waste disposal system collects and processes potentially radioactive reactor plant wastes, prior to release or removal from the plant site, to within regulatory limits. The liquid wastes are sampled prior to release using an isotopic identification as necessary. Radiation monitors are provided to maintain surveillance over the release operation. The system is capable of processing all wastes assuming continuous unit operation and 1% failed fuel. With the exception of the portions of the system inside each of the Units 3 and 4 containments, which are essentially the same, the system is common to both units.

At least two valves must be manually opened to permit discharge of liquid or gaseous waste from the waste disposal system. One of these valves is normally locked closed. During release, the effluent is monitored, and the release terminated if the radioactivity level exceeds a predetermined value. Activity release limits are given in the Offsite Dose Calculation Manual (ODCM) in accordance with the Technical Specifications.

The liquid waste disposal system is comprised of various subsystems in four areas of the plant. These areas are the containments of Units 3 and 4, the auxiliary building and the radwaste facility. The liquid waste disposal system utilizes tanks and pumps from other plant systems to store and transfer the plant radioactive liquid wastes. The CVCS holdup tanks normally receive letdown water from the RCS, the PRTs and the reactor coolant drain tanks (RCDTs). The RCDTs are used to collect RCS water in the containments and transfer it to the CVCS holdup tanks in the auxiliary building. The remaining portion of liquid radwaste system in the auxiliary building is the waste holdup tank, the floor drain system, associated pumps and the liquid release header. In the radwaste facility, the liquid radwaste system consists of a waste holdup tank, portable demineralizers, three waste monitor tanks and their transfer pumps. The monitor tanks are used to holdup and store liquid from the laundry tanks in the liquid radwaste system.

The waste holdup tank and waste monitor tanks are housed in cubicles to provide shielding and contain the liquid wastes from the tanks in the event of a tank rupture or leak.

The gaseous waste disposal system collects, stores, processes and discharges the radioactive gases from the plant. This system consists of the vent header, two waste gas compressors, six gas decay tanks, waste gas release valve, and associated piping, valves, controls and instrumentation.

The solid waste disposal system is designed to collect and store spent demineralizer resin and transfer the resin into shielded shipping casks for transportation to an approved off-site storage facility for disposal.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Common
5610-M-3061, Sheet 1
5610-M-3061, Sheet 2
5610-M-3061, Sheet 3
5610-M-3061, Sheet 4
5610-M-3061, Sheet 5
5610-M-3061, Sheet 6
5610-M-3061, Sheet 7
5610-M-3061, Sheet 8
5610-M-3061, Sheet 9
5610-M-3061, Sheet 10
5610-M-3061, Sheet 11
5610-M-3061, Sheet 12
5610-M-3061, Sheet 13
5610-M-3061, Sheet 14
5610-M-3061, Sheet 15

Turkey Point Unit 3
5613-M-3061, Sheet 1
5613-M-3061, Sheet 2

Turkey Point Unit 4
5614-M-3061, Sheet 1
5614-M-3061, Sheet 2

The subsequent license renewal boundaries of this system, based on its safety-related function, exist at containment penetrations P-5, P-10, P-23, P-31, and P-52, and at cavity drain valves 12-001 and 12-002, on both units. The boundaries of nonsafety-related functions that could affect safety-related functions exist at the RHR sump pumps and discharge piping.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure integrity at the containment penetrations including containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

(2) The RHR sump pumps protect the RHR pumps and heat exchangers from possible failure due to internal flooding.

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

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

UFSAR References

Section 11.1

Components Subject to AMR

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

Table 3.3.2-8 provides the results of the AMR.

Table 2.3.3-8
Waste Disposal Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Drain	Pressure boundary
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (tubes)[2]	Pressure boundary
Heat exchanger (tubesheet)	Pressure boundary
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.3-8

1. See Section 2.3.3.16 for additional information regarding components with an intended function of leakage boundary (spatial).
2. Heat transfer is not an SLR component intended function for this component.

2.3.3.9 Plant Air

Description

The plant air systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units. The air systems include breathing air, instrument air, nitrogen gas and hydrogen gas.

A majority of the breathing air system has been abandoned in-place because it is no longer utilized. The remaining portions of this system are the self-contained breathing apparatus fill station, the containment penetrations, and the headers inside containment.

The instrument air system provides a reliable source of dry, oil-free air for operation of instrumentation, controls, and air-operated valves. Instrument air is provided for the normal operation of many safety-related components (i.e., main steam isolation valves (MSIVs), pressurizer power operated relief valves (PORVs), and AFW system). The PORVs and AFW systems are provided with backup sources of nitrogen.

The instrument air system for each unit includes one diesel-engine-driven compressor and one motor-driven compressor, two aftercoolers, one receiver, one oil/water separator (mist eliminator), two parallel dryer pre-filters, one unit dryer, two parallel particulate after filters, distribution piping, valves and controls. The instrument air systems for Units 3 and 4 are interconnected so that either unit may serve as a backup source of compressed air for the other unit. In addition, the instrument air system has a common dryer and two parallel particulate after filters that can be placed in service for either Unit 3 or Unit 4. Current plant configuration has one electric compressor supplying both units with the remaining electric and the diesel compressors in standby, available to automatically start on low system pressure.

The quality of the air provided by the instrument air system is important to proper functioning of the end-use components. The primary method of removing particulates and debris from the air stream is by filters installed at each end-use component. In addition to this, particulate filters in the dryer outlet stream remove particulates before the air gets into the instrument air system piping.

The method used to reduce moisture is by centrifugal moisture separators at the compressor aftercoolers and at the air receiver, as well as desiccant dryers at the outlet of the air receiver.

The nitrogen gas system supplies inert, cover, and purge gas to various pieces of equipment both inside and outside containment. The system is divided into two sections: high pressure and low pressure. In case of an instrument air system failure, the nitrogen system provides safety-related backup nitrogen supply to the AFW system air-operated valves and the pressurizer PORVs.

The hydrogen gas system provides an efficient cooling and heat transfer medium for the turbine generators by maintaining hydrogen gas pressure in the generator at desired values. Additionally, the hydrogen gas system provides hydrogen to the gas space of the volume control tanks (VCTs) of Units 3 and 4 for RCS oxygen savaging.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below.   There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Common
5610-M-3101, Sheet 1
5610-M-3101, Sheet 2
5610-M-3013, Sheet 1
5610-M-3013, Sheet 2
5610-M-3065, Sheet 1
5610-M-3065, Sheet 2
5610-M-3065, Sheet 3

Turkey Point Unit 3
5613-M-3101, Sheet 1
5613-M-013-1, Sheet 3
5613-M-013-2, Sheet 4
5613-M-3013, Sheet 1
5613-M-3013, Sheet 2
5613-M-3013, Sheet 3
5613-M-3013, Sheet 4
5613-M-3013, Sheet 5
5613-M-3013, Sheet 7
5613-M-3013, Sheet 8
5613-M-3013, Sheet 9
5613-M-3013, Sheet 10
5613-M-3013, Sheet 11
5613-M-3013, Sheet 12
5613-M-3041, Sheet 4
5613-M-3047, Sheet 2
5613-M-3075, Sheet 3

Turkey Point Unit 4
5614-M-3101, Sheet 1
5614-M-3013, Sheet 1
5614-M-3013, Sheet 2
5614-M-3013, Sheet 3
5614-M-3013, Sheet 4

5614-M-3013, Sheet 5
5614-M-3013, Sheet 7
5614-M-3041, Sheet 4
5614-M-3047, Sheet 2
5614-M-3075, Sheet 3

Aside from its SR containment isolation design requirements, plant air is required to support the operation of valves that perform an intended function during a fire or SBO event. Due to the limited number of subsequent license renewal components supported by instrument air, only those portions of the system that provide the main flow path from the diesel-engine-driven instrument air compressors to the applicable components were designated within the scope of subsequent license renewal. Note that the system boundaries were established at the first manual isolation valve off the main flow path to the applicable components.

The air compressors at Turkey Point are both active components and complex assemblies; therefore, the entire air compressor assemblies are not subject to an aging management review. Numerous passive components associated with the air compressors are subject to an aging management review and are included in the plant air systems.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure integrity including containment isolation.

(2) Provide backup nitrogen supply to the air actuators for AFW valves and pressurizer PORVs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection, for the EQ Program and for SBO.

<u>UFSAR References</u>

Section 9.17

Components Subject to AMR

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

Table 3.3.2-9 provides the results of the AMR.

Table 2.3.3-9
Air Systems Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Pressure boundary
Dryer	Pressure boundary
Filter housing[1]	Pressure boundary
Heat exchanger[2]	Pressure boundary
Flex hose	Pressure boundary
Orifice[3]	Pressure boundary
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Rupture disc	Pressure boundary
Strainer body	Pressure boundary
Thermowell	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.3-9

1. Filter elements are replaced periodically.
2. Heat transfer is not an SLR component intended function for this component.
3. Throttle is not an SLR component intended function for this component.

2.3.3.10 Normal Containment Ventilation

Description

The normal containment ventilation systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The normal containment ventilation system (NCVS) is comprised of two systems: the normal containment cooling system (NCCS) and the control rod drive mechanism cooling system (CRDMCS). The NCVS provides air circulation and cooling to maintain containment bulk ambient temperature at or below 120°F but not exceeding 125°F for a cumulative period of two weeks.

The NCCS consists of four normal containment coolers, ductwork, dampers, and provisions for air temperature monitoring. Each cooling unit is equipped with a cooling coil cooled by CCW, a belt-driven fan motor, and a fan and coil housing. Each unit discharges air through its own discharge damper to a common supply header, which supplies air to various ductwork plenums for distribution throughout the containment. The associated ductwork and manual dampers for the cooling system channel cool air flow to remote areas of the containment, such as reactor coolant pump compartments, around the steam generators and pressurizer, and below the reactor vessel.

The cooling units are located above the refueling floor, between the reactor coolant loop shield wall and containment wall. This location provides adequate shielding for equipment inspection during plant operation and shutdown conditions.

The CRDMCS supplements the NCCS and consists of two cooling units and a circular plenum around the CRDMs with interconnecting ductwork and dampers. Each cooling unit consists of a cooling coil cooled by CCW and a direct-driven, vane-axial type fan. Air is drawn from the containment atmosphere down through the CRDM shroud. Around the shroud is a circular plenum with holes in it, which is connected to the CRDM shroud. Air is drawn through the plenum, after passing around the CRDMs through the suction side ductwork, through the CRDM cooler dampers, into the cooling units, and discharged back to the containment atmosphere.

During plant operations, both CRDM coolers are in operation. The coolers are located on the operating deck (Elev. 58’) in containment near the reactor cavity. No credit is taken for the operation of the CRDMCS for safe shutdown. The CRDMCS prevents overheating of the CRDMs, but it is not essential for the control rods to perform their intended safety function.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3057, Sheet 1

Turkey Point Unit 4
5614-M-3057, Sheet 1

The boundaries for normal containment ventilation start at the normal containment coolers and CRDM coolers, including the pressure boundary function of the heat exchanger tubes. The in-scope equipment includes all of the normal containment ducting and associated components connected to these in-scope coolers as shown on the SLRBD.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide pressure boundary integrity of CCW (cooling coils),

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) None.

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

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

UFSAR References

Section 9.10

Components Subject to AMR

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

Table 3.3.2-10 provides the results of the AMR.

Table 2.3.3-10
Normal Containment Ventilation
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
HVAC closure bolting	Pressure boundary
Valve body	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Fan housing	Pressure boundary
Duct[1]	Pressure boundary

Notes for Table 2.3.3-10

1. Includes ventilation registers.

2.3.3.11 Plant Ventilation

The plant ventilation system includes the auxiliary building and electrical equipment room ventilation system and control building ventilation system, which are common to both units, and the EDG building ventilation systems and turbine building ventilation systems, which are unit-specific. Each is described below.

2.3.3.11.1 Auxiliary Building and Electrical Equipment Room Ventilation

Description

The auxiliary building ventilation system provides clean air to the operating areas of the auxiliary building and exhausts air from the equipment rooms and open areas of the building through a closed system. The system is designed to ensure adequate heat removal and control the direction of flow of potential airborne radioactivity from areas of low activity through areas of higher activity, to a common ventilation exhaust. This common ventilation exhaust ductwork directs the flow of air to the plant vent stack.

The electrical equipment room ventilation system provides cooling to the electrical equipment room under normal and emergency operation. During normal operation, two nonsafety-related chilled water units supply a common air handler to maintain the desired room temperature. In the event of a failure of the nonsafety-related system or a LOOP, safety-related air conditioning units will perform the same function. The safety-related units consist of two air conditioning units and two air handlers. Each air conditioning unit is functionally tied to an air handler unit.

Boundary

SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Turkey Point Common
5610-M-3060, Sheet 1
5610-M-3060, Sheet 3

The subsequent license renewal boundary for auxiliary building ventilation begins at the inlet to the auxiliary building supply fans V10 and V11, and includes system ductwork in the auxiliary building that provides supply air to safety-related rooms. The license renewal boundary continues through ductwork to the auxiliary building exhaust fans V8A and V8B, and ends at the fan exhaust ductwork located outside the auxiliary building. Note that the plant vent stack is only considered within the scope of subsequent license renewal as a nonsafety-related structure that could affect safety-related functions and is included with non-containment structures in Section 2.4.2.12.

The subsequent license renewal boundaries for electrical equipment room ventilation include the nonsafety-related chilled water piping and supports for air handling unit V78 located in the electrical equipment room. The subsequent license renewal boundary also includes the safety-related air conditioning units V76 and V77, and associated condensing units E231 and E232.

The fire dampers associated with the auxiliary building ventilation system are included with fire protection in Section 2.3.3.12.

Auxiliary building ventilation contains split system air conditioning units. For the purposes of screening, condensing units (including associated refrigeration circuit) associated with these systems were considered complex and active assemblies.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

Auxiliary building ventilation:

(1) None.

Electrical equipment room ventilation:

(1) Provide a temperature-controlled environment for the electrical equipment in the electrical equipment room during emergency operations to ensure room temperatures are kept below the maximum equipment design temperature of 104°F.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

Auxiliary building ventilation:

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

Electrical equipment room ventilation:

(1) None.

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

Auxiliary building ventilation:

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

Electrical equipment room ventilation:

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

UFSAR References

Section 9.8.1

Components Subject to AMR

Table 2.3.3-11 lists the plant ventilation component types that require AMR and their associated component intended functions.

Table 3.3.2-11 provides the results of the AMR.

2.3.3.11.2 Control Building Ventilation

Description

The control building ventilation system consists of the following three systems: the control room ventilation system (CRVS), the computer/cable spreading room ventilation system, and the dc equipment/inverter room ventilation system.

The control room atmosphere is filtered and conditioned by a separate ventilation system. The CRVS consists of two emergency supply fans, charcoal and high-efficiency particulate air (HEPA) filters, three air-conditioning units, two exhaust fans, dampers, radiation monitors and other process instrumentation, and supply and return ductwork. The three air conditioning units are identical, each consisting of a condensing unit and an associated air handler. The system circulates air from the control room and the control room offices through common return air ducts to the air handling units through roughing filters. Conditioned air is then directed back through a duct system for distribution throughout the control room. The CRVS air handlers are located in the mechanical equipment room, which is part of the control room envelope. The CRVS includes the control room emergency ventilation system (CREVS), which provides a controlled environment for the comfort and safety of control room personnel during anticipated operational occurrences and design basis accident conditions. As such, this system is classified safety-related.

As part of adopting the AST methodology, a compensatory filtration unit has been added to the CREVS, capable of manual actuation as a qualified backup to the CREVS recirculation filter train. Both of these filtration systems take suction through dual CREVS emergency air intake ducts, which are located in diverse wind directions.

The computer/cable spreading room ventilation system is designed to maintain the temperature and humidity requirements of vital electrical equipment installed in the cable spreading room and computer room, and, therefore, is classified safety-related. It also provides ventilation sufficient for intermittent occupation by operations and maintenance personnel. Since the computer room is not continuously manned, the system is designed for equipment reliability and not human habitability.

The computer/cable spreading room ventilation system has two chilled water system trains. Each train consists of a chiller package located on the control building roof, chilled water piping, and air handling units. The two chiller packages each contain an air-cooled condenser, a water chiller, a water pump, an air separator, and a surge tank. Each train of chilled water piping is connected to three air handling units, two in the computer room and one in the cable spreading room.

The dc equipment and inverter rooms are located east of the control room and the cable spreading room. This area comprises what is commonly called the control building annex. These rooms house the safety-related batteries, battery chargers, inverters, and dc load centers, in addition to other quality-related and nonsafety-related equipment.

The dc equipment and inverter room ventilation system provides cooling to these rooms and consists of one nonsafety-related split system air conditioning unit, two nonsafety-related self-contained air conditioning units, and four nonsafety-related battery room roof ventilators. The split system air conditioning unit (common) serves all of the dc equipment and inverter rooms, while each self-contained air conditioning unit serves the north and south dc equipment and inverter rooms separately. Ducting for these units distributes the air throughout the two levels.

<u>Boundary</u>

The SLR boundaries are reflected on the SLRBDs listed below. The primary difference between the current boundaries and those identified as part of the original Turkey Point license renewal effort involve the addition of the compensatory filter unit to the CREVS.

Turkey Point Common
5610-M-3025, Sheet 1
5610-M-3025, Sheet 2
5610-M-3025, Sheet 3

The subsequent license renewal boundaries for the control room ventilation essentially encompass the entire system. Portions of the system outside the subsequent license renewal boundary include system transitions to outside air intakes and discharges from the control room kitchen and toilet.

The subsequent license renewal boundaries for the computer/cable spreading room ventilation system essentially encompass the entire system. Portions of the system outside the subsequent license renewal boundary flags include the water makeup piping upstream of check valves CWS-005A and CWS-005B, and the instrument air connections to TCV-6522A/B, TCV-6530A/B, and TCV-6534A/B.

The subsequent license renewal boundaries for the dc equipment and inverter room ventilation system include all HVAC equipment, ductwork, duct supports, associated refrigerant tubing and drain piping, with the exception of exhaust fans V60 through V63 and their associated ductwork.

The fire dampers in the control building ventilation system are included with fire protection, Section 2.3.3.12.

The control building ventilation systems contain split system air conditioning units and/or chilled water systems. For the purposes of screening, chiller packages and condensing units (including associated refrigeration circuit) associated with these systems were considered complex and active assemblies.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide a temperature-controlled environment for the electrical equipment and personnel in the control room, mechanical equipment room, cable spreading room and computer room during normal and emergency operations to ensure room temperatures are kept below the electrical equipment design temperature of 104°F.

(2) Maintain a positive pressure in the control room and mechanical equipment room under accident conditions.

(3) Limit dose to operators in the control room under accident conditions to the dose acceptance criteria specified in General Design Criteria (GDC) 19.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.9.1
Section 9.9.2
Section 9.9.3

Components Subject to AMR

Table 2.3.3-11 lists the plant ventilation component types that require AMR and their associated component intended functions.

Table 3.3.2-12 provides the results of the AMR.

2.3.3.11.3 Emergency Diesel Generator Building Ventilation

Description

EDG building ventilation is required to provide cooling functions for the EDGs and associated equipment. EDG building ventilation is different for Turkey Point Units 3 and 4. EDG building ventilation is necessary to ensure proper operation of the EDGs and other safety-related electrical equipment.

Unit 3 EDG building ventilation system is a rather simple system consisting of wall-mounted, axial flow exhaust fans and short runs of discharge ductwork through the Unit 3 EDG radiator area. There is one fan for each EDG, and the fans operate to maintain cooling in the rooms when the EDGs are running to ensure room temperature is less than that specified for the EDG horsepower rating. There is no system description for the Unit 3 EDG building ventilation system in the Turkey Point UFSAR.

The Unit 4 EDG rooms are each served by one nonsafety-related ventilation fan when its associated EDG is not operating. Each fan serves as an exhaust fan for its respective EDG room. These fans exhaust through a louvered opening on the south wall of the EDG building. There are also two exhaust hoods on the roof to accommodate cooling if the ventilation fans were to fail. When each EDG is running, the air intake into the room is provided by the operation of the radiator cooling fans. The Unit 4 diesel oil transfer pump rooms are each served by one nonsafety-related ventilation fan. This fan serves as an exhaust fan for the room. The air intake is via a louvered opening. Due to the arrangement of the intake louver and exhaust fan, these rooms are kept at a negative pressure. These fans are designed to maintain room temperature below 104°F. The EDG control panel rooms are each served by a nonsafety-related air conditioning unit and a safety-related ventilation fan. The nonsafety-related air conditioning unit is mounted on the Unit 4 EDG building roof. Each EDG control panel rooms have a safety-related ventilation fan. These ventilation fans act as a supply fan to the rooms and exhausts via a louvered opening. Each of the 4160V switchgear rooms have a nonsafety-related air conditioning unit and two redundant safety-related ventilation fans powered from independent sources.

Boundary

SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
No drawing available

Turkey Point Unit 4
5614-M-3108, Sheet 1

The subsequent license renewal boundaries for the 4A and 4B EDG rooms are at the inlet and exhaust of louvers L2A and L2B. For the 4A and 4B control panel rooms, the subsequent license renewal boundaries are at the inlet of backdraft dampers BD3A1 and BD3B1, and the outlet of associated louvers L1A1 and L1B1. Additional subsequent license renewal boundaries are at intake hoods for vent fans 4V63A and 4V63B, and associated fan exhaust dampers BD2A4 and BD2B4.

For the 3D and 4D switchgear rooms, the subsequent license renewal boundaries are at the inlet of backdraft dampers BD2A3 and BD2B3, and the outlet of associated louvers L1A2 and L1B2. Additional subsequent license renewal boundaries are at intake hoods for vent fans 4V65A/4V65B and 3V65A/3V65B, and associated fan exhaust dampers BD2A1/BD2B1 and BD2A2/BD2B2.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

Unit 3

(1) None.

Unit 4

(1) Provide a temperature controlled environment for the 3D and 4D 4160V switchgear and the Unit 4 EDG control panels during emergency operations to ensure room temperatures are kept below the electrical equipment design temperature of 104°F.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

Unit 3 only:

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

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

Units 3 and 4:

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

UFSAR References

N/A

Components Subject to AMR

Table 2.3.3-11 lists the plant ventilation component types that require AMR and their associated component intended functions.

Table 3.3.2-13 provides the results of the AMR.

2.3.3.11.4 Turbine Building Ventilation

Description

The turbine building ventilation systems are essentially identical for Units 3 and 4. The turbine building ventilation system consists of the load center and switchgear rooms ventilation system and the steam generator feed pump ventilation system.

The load center and switchgear rooms ventilation system is designed to remove the heat dissipated by all equipment in the load center and switchgear rooms during normal plant operation and emergency conditions. The chillers, pumps, air separators, expansion tanks, piping and control panels are all located on the turbine deck. There are eight air handling units, including their related piping and controls, and two load centers exhaust fans located inside the conditioned space.

The steam generator feed pump ventilation system provides cooling to the steam generator feed pump room. It consists of two roof ventilators. This system is classified as nonsafety-related, and it performs no safety-related functions.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3070, Sheet 1
5613-M-3070, Sheet 2

Turkey Point Unit 4
5614-M-3070, Sheet 1
5614-M-3070, Sheet 2

The subsequent license renewal boundaries for turbine building ventilation include all piping and associated components depicted on the SLRBD, with the exception of piping/fittings/tubing downstream of vents and drains, tornado dampers 3FD-1001 and 4FD-1001 and fans 3V-15 and 4V-15.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.16

Components Subject to AMR

Table 2.3.3-11 lists the plant ventilation component types that require AMR and their associated component intended functions.

Table 3.3.2-14 provides the results of the AMR.

Table 2.3.3-11
Plant Ventilation Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Cooler housing	Pressure boundary
Damper housing	Pressure boundary
Duct	Pressure boundary
Fan housing	Pressure boundary
Filter	Filter Pressure boundary
Filter housing[2]	Pressure boundary
Flex connection	Pressure boundary
Flex hose	Pressure boundary
Heat exchanger (header)	Pressure boundary
Heat exchanger (housing)	Pressure boundary
Heat exchanger (fins)	Heat transfer
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Heat transfer Pressure boundary Leakage boundary (spatial)[1]
Heat exchanger (water box)	Pressure boundary
HVAC closure bolting	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Sight glass	Pressure boundary
Strainer body	Pressure boundary

Table 2.3.3-11
Plant Ventilation Components
Subject to Aging Management Review (Continued)

Component Type	Component Intended Function(s)
Strainer element	Filter
Thermowell	Pressure boundary
Tank	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.3-11

1. See Section 2.3.3.16 for additional information regarding components with an intended function of leakage boundary (spatial).
2. Filter elements are replaced periodically.

2.3.3.12 Fire Protection

Description

Fire protection protects plant equipment in the event of a fire to ensure safe plant shutdown and minimize the risk of a radioactive release to the environment. The fire protection system consists of the fire water system, halon suppression system, fire detection and protection system, RCP oil collection system, alternate shutdown system and the safe shutdown system. Individual components that constitute the alternate shutdown system were screened with their respective systems. The majority of fire protection is common to Units 3 and 4. Those portions of fire protection that are unit-specific are essentially identical on both units.

Fire Water System

The normal supplies for the fire water system are two raw water tanks that are supplied from a city water main. Each tank has a dedicated volume of water for the fire water system with the remaining volume available to the plant service (domestic) water system.

A 10-inch diameter fire loop encompasses Units 3 and 4 supplied by two fire pumps, one electric-driven and the other diesel-driven, and two jockey pumps. One jockey pump maintains normal operating fire header pressure. The fire pumps automatically supply water to the fire loop on low header pressure. Fire hydrants are strategically located throughout the site.

The fire main piping and each fire pump has the capacity to supply required flow to the most remote fire hydrant simultaneously with operation of the largest capacity flow deluge system.

Automatic Pre-Action Sprinkler System

Automatic pre-action sprinkler systems are provided for the EDG buildings and the charging pump rooms. When on standby, air is supplied between the deluge valve and closed sprinkler heads.

Automatic Deluge Sprinkler System

Automatic deluge sprinkler systems are provided for the component cooling pump areas in the auxiliary building and the North-South breezeway between the auxiliary building and control building. The deluge system is a dry pilot line operation type, which means all piping downstream of the deluge valve is dry, and the spray nozzles are of the open type.

Fixed Water Spray System

Fixed water spray systems are provided to protect specific hazards in the instrument air equipment areas, main, auxiliary, startup and “C” bus transformer areas, and the hydrogen seal oil and turbine lube oil reservoir. These systems are similar to deluge systems in their piping and valve arrangements. They are distinguished by having spray nozzles that are directed toward the equipment to be covered.

Wet Pipe Sprinkler System

Wet pipe sprinkler systems are provided in the instrument air compressor areas, main condenser areas, Unit 3 and Unit 4 steam generator feed pump areas, auxiliary transformer areas, turbine building ground floor and mezzanine deck, and the 4A and 4B EDG building diesel oil transfer pump rooms. The system uses closed sprinkler heads that activate when the melting point of a fusible link is reached.

Halon Fire Suppression Systems

Independent, automatically actuated halon fire suppression systems are provided in the control building, including the cable spreading room, the cable chase at elevation 30' and the inverter rooms at elevation 42'.

Fire Dampers

Fire dampers are provided to prevent the spread of fire through HVAC penetrations to protect safe shutdown capability. Fire dampers are also used to isolate an area prior to Halon system actuation.

Reactor Coolant Pump Oil Collection System

The RCP oil collection system for each unit consists of a set of oil collection assemblies attached to each of the RCPs, connected drain piping, collection tank, drip pans and spray shields or enclosures. The RCP oil collection system is designed to collect and prevent the spread of lubricating oil from the RCP motors in the event of a leak.

<u>Boundary</u>

The SLR boundaries are reflected on the SLRBDs listed below. Although Turkey Point has implemented NFPA 805, there are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Common
5610-M-3016, Sheet 1
5610-M-3016, Sheet 2

5610-M-3016, Sheet 3
5610-M-3016, Sheet 4
5610-M-3016, Sheet 5
5610-M-3016, Sheet 6
5610-M-3016, Sheet 7
5610-M-3016, Sheet 8
5610-M-3016, Sheet 9
5610-M-3016, Sheet 10
5610-M-3016, Sheet 11
5610-M-3025, Sheet 1

Turkey Point Unit 3
5613-M-3041, Sheet 3

Turkey Point Unit 4
5614-M-3041, Sheet 3

The fire water system comprises a flow path from raw water tanks I and II through distribution piping (with sectionalizing control or isolation valves) to the yard hydrants, sprinklers or hose standpipes, and the deluge valve on each required deluge or spray system. This flow path includes an underground yard loop.

The fire water pumps discharge into a 10-inch cast iron underground fire main that encircles both Units 3 and 4. This 10-inch line is connected to the 6-inch underground fire main loop that encompasses Units 1 and 2 of the fossil plant.

The raw water tanks and the upstream valves on the city water (supply) side of the tanks, bound the system on one side. The loop around Units 3 and 4 is capable of being isolated from the non-nuclear portion of the system. This isolation can be achieved by closing valves 10-PIV-12, 10-PIV-4 and OSY-V-10-30 to the north (toward the fossil Units 1 and 2) and valves 10-PIV-33 and 10-PIV-40 to the south (to the south site area, the location of office buildings and warehouses). These valves, in conjunction with 10-PIV-75 (in the cold chemistry laboratory), establish the subsequent license renewal boundary for the fire protection system.

For pre-action sprinkler systems, the subsequent license renewal interface boundary was established at the pressure control valve for supervisory air.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Fire dampers associated with the control room ventilation system are classified as safety-related because their failure could prevent the ventilation system from performing its safety-related function.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) None.

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

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection.

UFSAR References

Section 9.6.1

Components Subject to AMR

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

Table 3.3.2-15 provides the results of the AMR.

Table 2.3.3-12
Fire Protection Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Damper housing	Pressure boundary
Expansion joint	Pressure boundary
Filter housing[1]	Pressure boundary
Fire hydrant	Pressure boundary
Flame arrestor	Fire prevention
Flexible hose	Pressure boundary
Heat exchanger (channel head)[2]	Pressure boundary
Heat exchanger (shell)[2]	Pressure boundary
Heat exchanger (tubes)[2]	Heat transfer Pressure boundary
Heat exchanger (tubesheet)[2]	Pressure boundary
Nozzle	Pressure boundary Spray
Orifice	Pressure boundary
Piping	Pressure boundary
Pump casing	Pressure boundary
RCP oil drip pans and enclosure	Pressure boundary
Strainer body	Pressure boundary
Strainer element	Filter
Tank	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.3-12

1. Filter elements are replaced periodically.
2. Diesel-driven fire pump engine cooler.

2.3.3.13 Emergency Diesel Generator Cooling Water

Description

The EDGs provide alternating current (ac) power to the onsite electrical distribution system to assure the capability for a safe and orderly shutdown. The systems are different for each unit as described below.

The EDG cooling water systems provide cooling to its associated EDG to permit proper operation under all EDG loading conditions. These systems function independently from other cooling water systems to assure that no single failure can affect the cooling of more than one EDG. While in standby, the EDG cooling water system maintains the diesel engine and lubricating oil's temperature, by means of a heater, in a pre-warmed condition to minimize diesel engine wear.

When the Unit 3 EDGs are operating, the cooling water system removes heat from the intake air in the turbocharger after cooler, engine water jackets, and the lubricating oil system, and transfers the heat to the radiator where fans remove the heat by forced air to the atmosphere.

When the Unit 4 EDGs are operating, cooled water is drawn through the lube oil cooler by the two cooling water pumps. One pump supplies cooling water to the right side inlet manifold and one side of the discharge manifold, and the other pump supplies cooling water to the other side of the manifold. A temperature control valve then allows the water to pass through the radiator, to reject the necessary heat, as required to maintain the correct temperature.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3022, Sheet 5
5613-M-3022, Sheet 6

Turkey Point Unit 4
5614-M-3022, Sheet 5
5614-M-3022, Sheet 6

The subsequent license renewal boundary for EDG cooling water includes all components within the system with the exception of the lube oil coolers. These heat exchangers are addressed with EDG fuel and lubricating oil. The Unit 3 boundary ends at drain valve 3-70-292B and the incoming valve from PWM, 3-20-449B. Unit 3 also includes the nonsafety-related piping and valves for structural integrity where they connect to these valves. The Unit 4 boundary ends at the cooling expansion tanks. The PWM line to the expansion tanks is included for leakage starting at the expansion tank and continuing until the piping goes below grating, as shown on the SLRBD.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide cooling water to support operation of the EDGs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.15

Components Subject to AMR

Table 2.3.3-13 lists the EDG cooling water component types that require AMR and their associated component intended functions.

Table 3.3.2-16 provides the results of the AMR.

Table 2.3.3-13
Emergency Diesel Generator Cooling Water
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Flexible hose	Pressure boundary
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (fins)	Heat transfer
Heat exchanger (housing)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Heat exchanger (water box)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Sight glass	Pressure boundary
Tank	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.3-13

1. See Section 2.3.3.16 for additional information regarding components with an intended function of leakage boundary (spatial).

2.3.3.14 Emergency Diesel Generator Air

Description

The EDG air systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The air intake and exhaust systems provide combustion air to its associated EDG and exhaust the combustion products to the atmosphere. Each EDG has its own independent combustion air intake and exhaust system to assure that no single failure can affect the operation of more than one EDG.

The air start systems store and provide sufficient starting air to ensure starting of its associated EDG. They are designed to function with sufficient independence from other EDG air start systems to assure that no single failure can affect the provision of sufficient starting air to more than one EDG.

Boundary

SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3022, Sheet 1
5613-M-3022, Sheet 2

Turkey Point Unit 4
5614-M-3022, Sheet 1
5614-M-3022, Sheet 2

The air start system subsequent license renewal boundary starts at the check valves feeding into the air receiver tanks and continues to the air start equipment located on the EDGs. Nonsafety-related piping connected to the check valves is included for structural support as shown on the SLRBD. The air start system subsequent license renewal boundary also ends at the normally closed drain valves associated with the system.

The air intake and exhaust system starts at the air intake filter, continues through the EDG, and ends at the engine exhaust piping. As the EDGs are considered a complex and active assemblies, subcomponents of the EDGs do not require aging management. The EDG complex assembly boundary starts at the flexible connection between the air intake filter and the turbo charger (with the turbo charger included in the complex assembly), and ends at the connection to the exhaust bellows.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide starting air, intake air and diesel engine exhaust to support operation of the EDGs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.15

Components Subject to AMR

Table 2.3.3-14 lists the EDG air component types that require AMR and their associated component intended functions.

Table 3.3.2-17 provides the results of the AMR.

Table 2.3.3-14
Emergency Diesel Generator Air
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Air motor	Pressure boundary
Bolting	Pressure boundary
Expansion joint	Pressure boundary
Filter housing	Pressure boundary
Filter element	Filter
Flex hose	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Tank	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

2.3.3.15 Emergency Diesel Generator Fuel and Lubricating Oil

Description

The EDG fuel and lubricating oil systems are different for each unit as described below.

The EDG 3A and 3B fuel oil system stores diesel oil in an onsite diesel oil storage tank (DOST), transfers the diesel oil to either one of the two diesel oil day tanks (one tank is associated with each EDG), and transfers the diesel oil from each EDG diesel oil day tank to its associated skid mounted tank.

The EDG 4A and 4B fuel oil system provides each of the EDGs with a completely independent diesel oil storage and transfer system. Each of these systems consists of a DOST, a diesel oil transfer pump, piping and valves, and a diesel oil day tank, which supplies fuel oil to the EDG diesel engine.

The EDG lube oil systems provide each EDG with a dedicated lubricating oil system, which includes measures to provide lubrication to the diesel engine wearing parts during standby conditions and/or normal and emergency operations. These systems maintain the lubricating oil's temperature in a pre-warmed condition to minimize diesel engine wear.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3022, Sheet 3
5613-M-3022, Sheet 4
5613-M-3022, Sheet 5
5613-M-3022, Sheet 6

Turkey Point Unit 4
5614-M-3022, Sheet 3
5614-M-3022, Sheet 4
5614-M-3022, Sheet 5
5614-M-3022, Sheet 6

The subsequent license renewal boundary for the Unit 3 EDG fuel oil system starts at the DOST, continues to the diesel oil day tank, through the skid tank (including the skid tank flame arrestor), and ends at the duplex fuel filter where the fuel system becomes part of the EDG complex assembly. The truck fill line and various vents and drains are included for structural integrity as shown on the SLRBD. The Unit 4 boundaries are very similar to Unit 3, with the notable difference being the Unit 4 EDGs do not have a skid tank.

The EDG lube oil system is a closed system and is entirely within the scope of subsequent license renewal. EDG fuel and lubricating oil does include the cooling water side of the lube oil coolers.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide diesel fuel and lubricating oil to support operation of the EDGs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

1. Perform a function that demonstrates compliance with the Commission’s regulations for fire protection, for ATWS and for SBO.

<u>UFSAR References</u>

Section 9.15

<u>Components Subject to AMR</u>

Table 2.3.3-15 lists the EDG fuel and lubricating oil component types that require AMR and their associated component intended functions.

Table 3.3.2-18 provides the results of the AMR.

Table 2.3.3-15
Emergency Diesel Generator Fuel and Lubricating Oil Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Filter housing[1]	Pressure boundary
Flame arrestor	Fire prevention
Flex hose	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Heat exchanger (channel head)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Sight glass	Pressure boundary
Tank	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary

Notes for Table 2.3.3-15

1. Filter elements are replaced periodically.

2.3.3.16 Auxiliary Systems in the Scope of 10 CFR 54.4(a)(2) for Spatial Interactions

As discussed in Section 2.1.3.3, the potential impact of nonsafety-related structure, system, or component (SSC) failures on safety functions can be either functional or physical. A functional failure is one where the failure of the nonsafety-related SSC to perform its function impacts a safety function. A physical failure is one where a safety function is impacted by the loss of structural or mechanical integrity of a nonsafety-related SSC in physical proximity to a safety-related SSC. Functional failures of nonsafety-related SSCs that could impact a safety function, and physical failures of nonsafety-related SSCs directly connected to safety-related SSCs, are identified with the individual system's screening evaluation. Scoping and screening for physical failures of nonsafety-related SSCs that could impact a safety function based on spatial interactions with auxiliary systems is addressed in this section.

The methodology to determine which nonsafety-related piping containing fluid, steam or oil and not connected to safety-related piping that could potentially affect safety-related equipment if it were assumed to fail is described in Section 2.1.3.3.

The following spatial interactions are described in Section 2.1.3.3.

Physical Impact for Flooding

The evaluation of interactions due to physical impact or flooding resulted in the inclusion of structures and structural components. Structures and structural components are reviewed in Section 2.4, Scoping and Screening Results: Structures.

Pipe Whip, Jet Impingement, Physical Impact due to FAC Failures

Systems containing nonsafety-related, high-energy lines that can affect safety-related equipment are included in the review for the criterion of 10 CFR 54.4(a)(2). Where this criterion included auxiliary systems, those systems are within the scope of SLR per 10 CFR 54.4(a)(2).

Leakage or Spray

Nonsafety-related system components or nonsafety-related portions of safety-related systems containing oil, steam or liquid are considered within the scope of SLR based on the criterion of 10 CFR 54.4(a)(2) if such components are located in a space containing safety-related SSCs. Auxiliary systems meeting this criterion are within the scope of SLR per 10 CFR 54.4(a)(2).

As described in Section 2.1.5.2.3, the spaces approach evaluation documents the nonsafety-related components that are directly or not directly connected that have the potential for spatial interaction by physical impact, flooding, pipe whip, jet impingement, harsh environments, and/or spray or leakage that could affect the safety-related functions of adjacent safety-related systems. Therefore, the in-scope SSCs identified by the spaces approach evaluation are documented in this section. The spaces approach evaluation is required in each building housing both safety-related systems and nonsafety-related systems.

The following buildings contain nonsafety-related auxiliary system components that satisfy the spatial interaction methodology by means of physical impact, flooding, pipe whip, jet impingement, harsh environments, and/or spray or leakage that could affect the safety-related functions of adjacent safety-related systems.

- Containments
- EDG buildings
- Control building
- Auxiliary building (includes fuel handling buildings and electrical equipment room)

Containments

The method of evaluation of the containments is detailed in Section 2.1.5.2.3. Evaluation results for 10 CFR 54.4(2)(2) for spatial interactions are as follows:

- Pipe Whip/Jet Impingement/Physical Contact - There is no nonsafety-related high-energy piping inside the Units 3 or 4 Containments. All high-energy piping is SR and thus within the scope of SLR in accordance with 10 CFR 54.4(a)(1).
- Spray/Leakage – For the reasons stated above, SR SSCs inside the Units 3 and 4 Containments are designed to accommodate the effects of moderate-energy piping system leakage and/or spray, without loss of function, regardless of the source. This is further supported by Turkey Point’s position regarding EQ of mechanical equipment in response to NUREG-0578 as documented in the EQ DBD.

Results – No nonsafety-related piping systems located within the Units 3 or 4 Containments are required to be included within the scope of SLR for 10 CFR 54.4(a)(2) for spatial interaction.

EDG Buildings

The EDG buildings are analyzed using the spaces approach as described in Section 2.1.5.2.3. Evaluation results for 10 CFR 54.4(2)(2) for spatial interactions are as follows:

- Pipe whip/jet impingement/physical contact – There is no nonsafety-related, high-energy piping inside the Units 3 or 4 EDG buildings.
- Spray/leakage – The Unit 3 EDG building contains small bore nonsafety-related service (domestic) water piping and associated components that provide make-up water to the EDG cooling water radiators. These nonsafety-related service water components could potentially affect safety-related EDG equipment if age-

related failures are assumed. The Unit 4 EDG building contains small bore nonsafety-related EDG cooling water and associated components that provide make-up water to the EDG cooling water expansion tanks. These nonsafety-related EDG cooling water components could potentially affect safety-related EDG equipment if age-related failures are assumed.

Results – The nonsafety-related service water and EDG cooling water piping and associated components noted above have been included in the scope of SLR as meeting the scoping criteria of 10 CFR 54.4(a)(2).

Control Building

The control building is analyzed using the spaces approach as described in Section 2.1.5.2.3 and includes the following:

(a) Control room,

(b) Cable spreading room and battery room,

(c) Computer room, and

(d) Reactor control rod drive equipment and 3B/4B motor control centers (MCCs).

Evaluation results for 10 CFR 54.4(2)(2) for spatial interactions are as follows:

- Pipe whip/jet impingement/physical contact – There is no nonsafety-related high-energy piping inside the in the control building.
- Spray/leakage – The control building contains small bore nonsafety-related service (domestic) water piping and associated components that supply water to the computer room. These nonsafety-related service water components could potentially affect safety-related electrical equipment if age-related failures are assumed.

Results – The nonsafety-related service water piping and associated components noted above have been included in the scope of SLR as meeting the scoping criteria of 10 CFR 54.4(a)(2).

Auxiliary Building

The auxiliary building is analyzed using the spaces approach as described in Section 2.1.5.2.3. Evaluation results for 10 CFR 54.4(2)(2) for spatial interactions are as follows:

- Pipe whip/jet impingement/physical contact – There is nonsafety-related high-energy piping inside the auxiliary building. All high-energy piping in the auxiliary building is safety-related and thus within the scope of SLR in accordance with 10 CFR 54.4(a)(1).

- Spray/leakage – The auxiliary building contains nonsafety-related piping and associated components that could potentially affect safety-related electrical equipment if age-related failures are assumed. The specific piping is as follows:
  - Small bore chilled water piping and associated components associated with electrical equipment room ventilation in the electrical equipment room.
  - Small bore service (domestic) water piping and associated components.
  - Small bore PWM piping and associated components in various areas.
  - Small bore CVCS piping and associated components in various areas.
  - Small bore primary sampling piping and associated components in various areas.
  - Small bore waste disposal piping and associated components in various areas.
  - Spent fuel pool skimmer piping and associated components.

Results – The nonsafety-related piping and associated components noted above have been included in the scope of SLR as meeting the scoping criteria of 10 CFR 54.4(a)(2).

<u>UFSAR References</u>

Section 9.2
Section 9.4.1
Section 9.6.2
Section 9.8.1
Section 9.8.2
Section 9.15
Section 11.1

<u>Subsequent LRBD</u>

Turkey Point Common
5610-M-3012, Sheet 1
5610-M-3012, Sheet 2
5610-M-3046, Sheet 2
5610-M-3046, Sheet 3
5610-M-3046, Sheet 4
5610-M-3060, Sheet 3

Turkey Point Unit 3
5613-M-3020, Sheet 2
5613-M-3033, Sheet 1
5613-M-3036, Sheet 1
5613-M-3047, Sheet 1
5613-M-3047, Sheet 2
5613-M-3061, Sheet 1

Turkey Point Unit 4
5614-M-3020, Sheet 2
5614-M-3022, Sheet 5
5614-M-3022, Sheet 6
5614-M-3033, Sheet 1
5614-M-3036, Sheet 1
5614-M-3047, Sheet 1
5614-M-3047, Sheet 2
5614-M-3061, Sheet 1

Components Subject to AMR

Table 2.3.3.16-1 lists the component types that require an AMR in the EDG buildings. This table also provides a reference to the table(s) providing the results of the AMR.

Table 2.3.3.16-2 lists the component types that require an AMR in the control building. This table also provides a reference to the table(s) providing the results of the AMR.

Table 2.3.3.16-3 lists the component types that require an AMR in the auxiliary building. This table also provides a reference to the table(s) providing the results of the AMR.

Table 2.3.3.16-1
Component Intended Functions for 10 CFR 54.4(a)(2)
Components in the Emergency Diesel Generators Buildings
Subject to Aging Management Review

System	Component Type	Intended Function	AMR Results
Service water[1]	Bolting	Leakage boundary (spatial)	Table 3.3.2-19
	Piping		
	Valve body		
EDG cooling water[2]	See Table 2.3.3-13 for a list of component types.	Leakage boundary (spatial)	Table 3.3.2-16

Notes for Table 2.3.3.16-1

1. Unit 3 EDG building only.
2. Unit 4 EDG building only.

Table 2.3.3.16-2
Component Intended Functions for 10 CFR 54.4(a)(2)
Components in the Control Building
Subject to Aging Management Review

System	Component Type	Intended Function	AMR Results
Service water	Bolting	Leakage boundary (spatial)	Table 3.3.2-19
	Piping		
	Valve body		

Table 2.3.3.16-3
Component Intended Functions for 10 CFR 54.4(a)(2)
Components in the Auxiliary Building
Subject to Aging Management Review

System	Component Type	Intended Function	AMR Results
Service water[1]	Bolting	Leakage boundary (spatial)	Table 3.3.2-19
	Piping		
	Valve body		
Electrical equipment room ventilation chilled water[2]	See Table 2.3.3-11 for a list of component types.	Leakage boundary (spatial)	Table 3.3.2-11
Primary water makeup[3]	See Table 2.3.3-5 for a list of component types.	Leakage boundary (spatial)	Table 3.3.2-5
Chemical and volume control[3]	See Table 2.3.3-4 for a list of component types.	Leakage boundary (spatial)	Table 3.3.2-4
Primary sampling[3]	See Table 2.3.3-6 for a list of component types.	Leakage boundary (spatial)	Table 3.3.2-6
Waste disposal[3]	See Table 2.3.3-8 for a list of component types.	Leakage boundary (spatial)	Table 3.3.2-8
Spent fuel pool cooling	See Table 2.3.3-3 for a list of component types.	Leakage boundary (spatial)	Table 3.3.2-3

<u>Notes for Table 2.3.3.16-3</u>

1. Main hallways and electrical equipment room.
2. Electrical equipment room.
3. Various areas.

2.3.4 Steam and Power Conversion System

The following systems are addressed in this section:

- Main Steam and Turbine Generators (2.3.4.1)
- Feedwater and Blowdown (2.3.4.2)
- Auxiliary Feedwater and Condensate Storage (2.3.4.3)
- Steam and Power Conversion Systems in the Scope of 10 CFR 54.4(a)(2) for Spatial Interactions (2.3.4.4)

2.3.4.1 Main Steam and Turbine Generators

Description

The main steam and turbine generator systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

Main steam transports saturated steam from the steam generators to the main turbine and other secondary steam system components. Main steam provides the principal heat sink for the RCS protecting the RCS and the steam generators from over pressurization, provides isolation of the steam generators during a postulated steam line break, and provides steam supply to the AFW pump turbines.

Steam from the three steam generators is transported to the main steam manifold through three steam pipes, and from the manifold to the main turbine stop valves through two steam pipes. The main steam manifold is a header that ties the three steam generators together in order to equalize the load on all three steam generators. Steam is transported through the containment penetrations. Auxiliary steam loads fed from the main steam line upstream of the MSIVs, provide steam to the turbine-driven AFW pumps and atmospheric steam dump valves.

The main steam headers contain steam line safety valves, atmospheric dump valves, steam line isolation valves, non-return check valves, instrumentation, steam generator wet lay-up isolation valves, and sample isolation valves.

The atmospheric steam dump consists of a single air-operated globe valve on each main steam line upstream of the MSIV and non-return check valve. The valves provide plant cooldown capability when the main condenser is unavailable. They also relieve excess pressure in the steam generators and can prevent lifting of the code safety valves.

Four safety valves are installed on each steam line and serve as a heat sink for the RCS if the main condenser is unavailable and the atmospheric steam dump valves cannot relieve the pressure.

Steam flow from each steam generator is capable of being isolated by an air-operated MSIV. These full flow swing check valves are held open against spring pressure by air from the plant instrument air system. In the event of a steam line rupture, the MSIVs and non-return check valves are required to quickly interrupt steam flow in either direction, thus preventing an uncontrolled blowdown from more than one steam generator. The isolation valves are located outside the containment as close to the building as possible and downstream of the atmospheric dump and safety valves.

Steam turbines convert the steam input from main steam to the plant's electrical generator, provide first-stage pressure input to the RPS, and provide isolation under certain postulated steam line break scenarios.

The turbines are tandem-compound condensing units consisting of one double-flow high-pressure element and two double-flow low-pressure elements. Steam from the main steam system is supplied to the high-pressure turbine through two turbine stop valves and four control valves. The control valves are used to throttle the steam flow to the turbine. The steam exits the high-pressure turbine, passes through the MSRs and is supplied to the two low-pressure turbines. Two of the four MSRs feed each low-pressure turbine.

<u>Boundary</u>

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Unit 3
5613-M-3072, Sheet 1
5613-M-3072, Sheet 2
5613-M-3072, Sheet 3
5613-M-3089, Sheet 1
5613-M-3089, Sheet 2

Turkey Point Unit 4
5614-M-3072, Sheet 1
5614-M-3072, Sheet 2
5614-M-3072, Sheet 3
5614-M-3089, Sheet 1
5614-M-3089, Sheet 2

The main steam system subsequent license renewal boundary starts at top of the steam generators with their associated vent valves. The vent sides of the steam dump valves and associated piping, as well as various other vent valves, are included for structural integrity. The subsequent license renewal boundary ends at the isolation valves for the condenser steam dump connections and at valves before reaching the MSRs. The system boundary ends in the header leading up to the turbine stop and bypass valves.

The turbine system subsequent license renewal boundaries start at the end of the main steam boundaries and continue to the main steam to high-pressure turbine stop and bypass valves.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure boundary integrity including containment isolation and the pressure boundary between the steam generators and the MSIVs.

(2) Provide isolation capability of the steam generators to establish control of fission products released to the secondary system from the primary system following a SGTR.

(3) Support decay heat removal by AFW following DBEs.

(4) Provide for RCS heat removal when the main condenser is not available and overpressure protection for the steam generators.

(5) Provide main steam isolation of the steam generators to limit steam release following DBEs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

(2) Support isolation of the MS system to prevent blowdown of a steam generator should an MSIV on an un-faulted steam generator fail to close.

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

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

<u>UFSAR References</u>

Section 10.2.2

<u>Components Subject to AMR</u>

Table 2.3.4-1 lists the main steam and turbine component types that require AMR and their associated component intended functions.

Table 3.4.2-1 provides the results of the AMR.

Table 2.3.4-1
Main Steam and Turbine Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Flow element	Pressure boundary Throttle
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Pressure boundary Structural integrity (attached) Leakage boundary (spatial)[1]
Steam traps	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.4-1

1. See Section 2.3.4.4 for additional information regarding components with an intended function of leakage boundary (spatial).

2.3.4.2 Feedwater and Blowdown

Description

The feedwater and blowdown systems for Units 3 and 4 are essentially identical. On this basis, the following discussion applies to both units.

The feedwater system on each unit consists of three separate subsystems. They include the main feedwater, steam generator blowdown (SGBD) and standby steam generator feedwater systems. Main feedwater and SGBD are unit-specific, and the standby steam generator feedwater system is common to both units.

The major components of the feedwater system for each unit include two steam generator feedwater pumps, two high-pressure feedwater heaters, and three steam generator feedwater control (or regulating) valves (FCVs).

The primary function of the main feedwater system is to remove heat from the RCS. This is accomplished by supplying preheated feedwater to the steam generators at a flow rate equal to steam flow and a pressure sufficiently greater than steam generator pressure to make up for losses due to flow through the FCVs, feedwater heaters and associated piping.

Each unit is equipped with two steam generator feedwater pumps.The feedwater pumps pump the water through the high-pressure feedwater heaters, for its final stage of preheating. Feedwater leaving the high-pressure feedwater heater splits into three feedwater headers that supply feedwater to the three steam generators. Flow to each steam generator is controlled by the FCVs, one for each steam generator. Upstream of each FCV is a motor-operated valve, which is the feedwater isolation valve. Downstream of the FCV is an air-operated stop check valve used to prevent backflow from the steam generator in the event of low differential pressure across the FCV.

The SGBD system assists in maintaining the required steam generator water chemistry by providing a means for removal of foreign matter that concentrates in the steam generator. The system has three independent blowdown lines (one per steam generator) that discharge into a common blowdown flash tank. SGBD is continuously monitored for radioactivity during plant operation.

The standby steam generator feedwater system is independent of the main feedwater system and the AFW system. The standby steam generator feedwater pumps are used to supply steam generator feedwater during startup, shutdown, and hot standby conditions. The system consists of two pumps that take suction from the demineralized water storage tank (DWST) and discharge to a common header upstream of the FCVs. The two pumps are independently powered; one pump is motor-driven and the other is diesel-driven. The diesel-driven pump is supplied by an independent fuel oil storage tank equipped with a flame arrestor.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Common
5610-M-3074, Sheet 1
5610-M-3074, Sheet 2

Turkey Point Unit 3
5613-M-3074, Sheet 1
5613-M-3074, Sheet 2
5613-M-3074, Sheet 3
5613-M-3074, Sheet 4
5613-M-3074, Sheet 5
5613-M-3014, Sheet 1
5613-M-3014, Sheet 2
5613-M-3078, Sheet 1

Turkey Point Unit 4
5614-M-3074, Sheet 1
5614-M-3074, Sheet 2
5614-M-3074, Sheet 3
5614-M-3074, Sheet 4
5614-M-3074, Sheet 5
5614-M-3014, Sheet 1
5614-M-3014, Sheet 2
5614-M-3078, Sheet 1

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure integrity including containment isolation and the pressure boundary between the steam generators and the containment isolation valves outside containment.

(2) Support decay heat removal by the AFW system following DBEs.

(3) Provide feedwater isolation following a LOCA or an MSLB to limit feedwater flow to the steam generators.

(4) Provide blowdown isolation to prevent loss of steam generator inventory following DBEs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 10.2.2
Section 10.2.4.3

Components Subject to AMR

Table 2.3.4-2 lists the feedwater and blowdown component types that require AMR and their associated component intended functions.

Table 3.4.2-2 provides the results of the AMR.

Table 2.3.4-2
Feedwater and Blowdown Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary Leakage boundary (spatial)[1]
Flame arrestor	Fire prevention
Flow element[2]	Pressure boundary Leakage boundary (spatial)[1]
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (tubesheet)	Pressure boundary
Heat exchanger (tubes)[3]	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary Leakage boundary (spatial)[1]
Piping and piping components	Pressure boundary Structural integrity (attached) Leakage boundary (spatial)[1]
Pump casing	Pressure boundary Leakage boundary (spatial)[1]
Strainer body	Pressure boundary
Tank	Pressure boundary
Thermowell	Pressure boundary
Tubing	Pressure boundary
Valve body	Pressure boundary Leakage boundary (spatial)[1]

Notes for Table 2.3.4-2

(1) See Section 2.3.4.4 for additional information regarding components with an intended function of leakage boundary (spatial).

(2) Throttle is not an SLR component intended function for this component.

(3) Heat transfer is not an SLR component intended function for this component.

2.3.4.3 Auxiliary Feedwater and Condensate Storage

Description

The auxiliary feedwater (AFW) system is a shared system between Units 3 and 4. The AFW system supplies feedwater to the steam generators during transients when normal feedwater sources are not available.

The CSTs are the normal water supply source for the auxiliary feedwater system. Each unit has a tank that is filled from the makeup water treatment system. The three common AFW pumps take suction from either CST through check valves and normally locked open gate valves.

The three AFW pumps discharge through their check valves to one of two redundant discharge headers. The administratively controlled, locked open and locked closed valve configuration aligns the pumps so that pump A discharges to the train 1 feedwater header, and pumps B and C normally discharge to the train 2 feedwater header. This valve lineup is maintained when AFW is in standby mode and both units are operating. This assures redundant flow paths of auxiliary feedwater to the steam generators.

Normally, upon initiation of AFW operation, all three pumps will start (with both units operating), supplying the affected steam generators with AFW through both trains. Each train can supply feedwater to each steam generator through a flow control valve, flow transmitters and isolation valves. After passing through the flow control valve, the lines then tap into the feedwater lines between the main feedwater control valves and the steam generators.

Boundary

The SLR boundaries are reflected on the SLRBDs listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Turkey Point Common
5610-M-3075, Sheet 1
5610-M-3075, Sheet 2

Turkey Point Unit 3
5613-M-3018, Sheet 1
5613-M-3075, Sheet 1
5613-M-3075, Sheet 2
5613-M-3075, Sheet 3

Turkey Point Unit 4
5614-M-3018, Sheet 1

5614-M-3075, Sheet 1
5614-M-3075, Sheet 2
5614-M-3075, Sheet 3

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Supply feedwater to the steam generators at times when the normal feedwater systems are not available to prevent pressurizer overfilling, prevent primary system overpressure and limit peak fuel clad temperature.

(2) Isolate the AFW steam and feedwater supply lines associated with the ruptured steam generator following a SGTR event.

(3) Limit feedwater flow to the steam generators in the event of a MSLB in order to limit positive reactivity insertion to the core and to prevent containment overpressure caused by overfeeding the faulted steam generator.

(4) Maintain containment pressure boundary integrity.

(5) Provide sufficient condensate inventory for sustained operation following a LOOP (for a period of 13 hours; four hours at hot standby followed by a nine-hour cooldown to RHRS entry conditions).

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

Section 9.11

Components Subject to AMR

Table 2.3.4-3 lists the auxiliary feedwater and condensate storage component types that require AMR and their associated component intended functions.

Table 3.4.2-3 provides the results of the AMR.

Table 2.3.4-3
Auxiliary Feedwater and Condensate Storage
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Pressure boundary
Flow element	Pressure boundary Throttle
Heat exchanger (channel head)	Pressure boundary
Heat exchanger (shell)	Pressure boundary
Heat exchanger (tubes)	Pressure boundary Heat transfer
Heat exchanger (tubesheet)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing	Pressure boundary
Tank	Pressure boundary
Tubing	Pressure boundary
Turbine housing	Pressure boundary
Valve body	Pressure boundary

2.3.4.4 Steam and Power Conversion Systems in the Scope of 10 CFR 54.4(a)(2) for Spatial Interactions

As discussed in Section 2.1.3.3, systems within the scope of SLR based on the criterion of 10 CFR 54.4(a)(2) interact with safety-related systems in one of two ways: functional or physical. A functional failure is one where the failure of the nonsafety-related SSC to perform its function impacts a safety function. A physical failure is one where a safety function is impacted by the loss of structural or mechanical integrity of a nonsafety-related SSC in physical proximity to a safety-related SSC. Functional failures of nonsafety-related SSCs that could impact a safety function, and physical failures of nonsafety-related SSCs directly connected to safety-related SSCs, are identified with the individual system's screening evaluation. Scoping and screening for physical failures of nonsafety-related SSCs that could impact a safety function based on spatial interactions with steam and power conversion systems are addressed in this section.

The methodology to determine which nonsafety-related piping containing fluid, steam or oil and not connected to safety-related piping that could potentially affect safety-related equipment if it were assumed to fail is described in Section 2.1.3.3.

The following spatial interactions are described in Section 2.1.3.3.

<u>Physical Impact for Flooding</u>

The evaluation of interactions due to physical impact or flooding resulted in the inclusion of structures and structural components. Structures and structural components are reviewed in Section 2.4, Scoping and Screening Results: Structures.

<u>Pipe Whip, Jet Impingement, Physical Impact due to FAC Failures</u>

Systems containing nonsafety-related, high-energy lines that can affect safety-related equipment are included in the review for the criterion of 10 CFR 54.4(a)(2). Where this criterion included steam and power conversion systems, those systems are within the scope of SLR per 10 CFR 54.4(a)(2).

<u>Leakage or Spray</u>

Nonsafety-related system components or nonsafety-related portions of safety-related systems containing oil, steam or liquid are considered within the scope of SLR based on the criterion of 10 CFR 54.4(a)(2) if such components are located in a space containing safety-related SSCs. Steam and power conversion systems meeting this criterion are within the scope of SLR per 10 CFR 54.4(a)(2).

As described in Section 2.1.5.2.3, the spaces approach evaluation documents the nonsafety-related components that are directly or not directly connected that have the potential for spatial interaction by physical impact, flooding, pipe whip, jet impingement, or harsh environments, and/or spray or leakage that could affect the safety-related functions of adjacent safety-related systems. Therefore, the in-scope SSCs identified by the spaces approach evaluation are documented in this section. The spaces approach evaluation is required in each building housing both safety-related systems and nonsafety-related systems.

The following structures contain nonsafety-related components of steam and power conversion systems that satisfy the spatial interaction methodology by means of physical impact, flooding, pipe whip, jet impingement, or harsh environments, and/or spray or leakage that could affect the safety-related functions of adjacent safety-related systems.

- Turbine Building
- Yard Structures

Turbine Building

The turbine building is analyzed as described in Section 2.1.5.2.3. Evaluation results for 10 CFR 54.4(2)(2) for spatial interactions are as follows:

- Pipe whip/jet impingement/physical contact – All high-energy piping within the turbine building is located outdoors. Additionally, significant portions of the nonsafety-related main steam and feedwater piping and associated components are within the scope of SLR because they meet other scoping criteria of 10 CFR 54.4(a).

  Other nonsafety-related, high-energy piping in the turbine building includes portions of the auxiliary steam, main steam, condensate, extraction steam and feedwater heater drain and vent systems. Piping segments of the auxiliary steam, condensate, feedwater, and feedwater heater drains and vents systems could potentially affect safety-related cable trays and conduit in certain areas of the turbine building if age-related failures are assumed. The specific piping is as follows:

  - Portions of the nonsafety-related auxiliary steam piping.
  - Portions of the nonsafety-related main steam piping.
  - Portions of the nonsafety-related condensate piping.
  - Portions of the nonsafety-related feedwater piping.
  - Portions of the nonsafety-related feedwater heater drains and vent piping.

- Spray/Leakage – The Unit 3 and 4 turbine building is essentially an outdoor area. All safety-related equipment that is in proximity to nonsafety-related piping is designed for outdoor service and is periodically exposed to torrential rains and wind. Therefore, this safety-related equipment would not be impacted by leakage or spray from moderate- or low-energy piping.

Results – The nonsafety-related piping and associated components noted above have been included in the scope of SLR as meeting the scoping criteria of 10 CFR 54.4(a)(2).

Yard Structures

The yard structures are analyzed as described in Section 2.1.5.2.3. Evaluation results for 10 CFR 54.4(2)(2) for spatial interactions are as follows:

- Pipe whip/jet impingement/physical contact – All high-energy piping within the yard structures is located outdoors between the containments, main steam and feedwater platforms, and the turbine building. Additionally, nonsafety-related piping and associated components in this area from main steam and turbine, as well as feedwater and blowdown, are within the scope of license renewal because they meet other scoping criteria of 10 CFR 54.4(a). Other nonsafety-related, high-energy piping in the yard structures includes portions of the auxiliary steam, condensate, and feedwater heater drains and vents systems. Piping segments of the auxiliary steam, condensate, and feedwater heater drains and vents systems could potentially affect safety-related cable trays and conduits in certain areas of the yard structures if age-related failures are assumed. The specific piping is as follows:

  - Portions of the nonsafety-related auxiliary steam piping.
  - Portions of the nonsafety-related condensate piping.
  - Portions of the nonsafety-related feedwater heater drains and vent piping.

- Spray/Leakage – This is an outdoor area. All safety-related equipment is designed for outdoor service and is periodically exposed to torrential rains and wind. Therefore, this safety-related equipment would not be impacted by leakage or spray from moderate- or low-energy piping.

Results – The nonsafety-related piping and associated components noted above have been included in the scope of SLR as meeting the scoping criteria of 10 CFR 54.4(a)(2).

UFSAR References

Section 10.2

SLR Boundary Drawings

Turkey Point Unit 3
5613-M-3010, Sheet 2
5613-M-3014, Sheet 3
5613-M-3072, Sheet 1
5613-M-3073, Sheet 2
5613-M-3073, Sheet 3
5613-M-3074, Sheet 1
5613-M-3081, Sheet 2
5613-M-3081, Sheet 3
5613-M-3081, Sheet 4
5613-M-3082, Sheet 1
5613-M-3084, Sheet 1
5613-M-3089, Sheet 2

Turkey Point Unit 4
5614-M-3010, Sheet 2
5614-M-3014, Sheet 3
5614-M-3072, Sheet 1
5614-M-3073, Sheet 2
5614-M-3073, Sheet 3
5614-M-3074, Sheet 1
5614-M-3081, Sheet 2
5614-M-3081, Sheet 3
5614-M-3082, Sheet 1
5614-M-3084, Sheet 1
5614-M-3089, Sheet 2

Components Subject to AMR

Table 2.3.4.4-1 lists the component types that require AMR in the turbine building. This table also provides a reference to the table(s) providing the results of the AMR.

Table 2.3.4.4-2 lists the component types that require AMR in the yard structures. This table also provides a reference to the table(s) providing the results of the AMR.

Table 2.3.4.4-1
Component Intended Functions for 10 CFR 54.4(a)(2)
Components in the Turbine Building
Subject to Aging Management Review

System	Component Type	Intended Function	AMR Results
Auxiliary steam[1]	Bolting	Leakage boundary (spatial)	Table 3.4.2-4
	Piping		
	Piping and piping components		
	Valve body		
Main steam and Turbine Generators[2]	See Table 2.3.4-1 for a list of component types	Leakage boundary (spatial)	Table 3.4.2-1
Condensate[3]	Bolting	Leakage boundary (spatial)	Table 3.4.2-5
	Orifice		
	Piping		
	Piping and piping components		
	Thermowell		
	Valve body		
Feedwater and Blowdown[4]	See Table 2.3.4-2 for a list of component types	Leakage boundary (spatial)	Table 3.4.2-2
Feedwater heater drains and vents[5]	Bolting	Leakage boundary (spatial)	Table 3.4.2-6
	Flow element		
	Piping		
	Piping and piping components		
	Thermowell		
	Valve body		

Notes for Table 2.3.4.4-1

1. Various areas.
2. Supply to turbine gland seal valves.
3. Outlet of the No. 2 feedwater heaters to the main feedwater pump suction.
4. Feedwater pump recirculation lines.
5. Unit 3 only – heater drain pump discharge to main feedwater pump suction; portions of the 3A, 3B, and 4B reheater drain tanks; and No. 6 to No. 5 feedwater heater drains.

Table 2.3.4.4-2
Component Intended Functions for 10 CFR 54.4(a)(2)
Components in the Yard Structures
Subject to Aging Management Review

System	Component Type	Intended Function	AMR Results
Auxiliary steam[1]	Bolting	Leakage boundary (spatial)	Table 3.4.2-4
	Piping		
	Piping and piping components		
	Valve body		
Condensate[2]	Bolting	Leakage boundary (spatial)	Table 3.4.2-5
	Orifice		
	Piping		
	Piping and piping components		
	Thermowell		
	Valve body		
Feedwater heater drains and vents[3]	Bolting	Leakage boundary (spatial)	Table 3.4.2-6
	Flow element		
	Piping		
	Piping and piping components		
	Thermowell		
	Valve body		

Notes for Table 2.3.4.4-2

1. Various areas.
2. Downstream of No. 4 feedwater heaters to main feedwater pump suction line.
3. No. 6 to No. 5 feedwater heater drains.

2.3.5 References

2.3.5.1 NRC letter from Jason C. Paige to Mano Nazar dated June 23, 2011, "Turkey Point Units 3 and 4 – Issuance of Amendments Regarding Alternate Source Term (TAC Nos. ME1624 AND ME1625)," ML110800666.

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

The following structures and structural components are within the scope of SLR.

- Containment Structure and Internal Structural Components (Section 2.4.1)
- Non-Containment Structures (Section 2.4.2)

2.4.1 Containment Structure and Internal Structural Components

Each Turkey Point containment is a domed-concrete, steel-reinforced structure that houses the reactor vessel, RCS, RCS supports, and other important systems that interface with the RCS. Additionally, each containment houses and supports components required for plant refueling. This includes the polar crane, refueling cavity, and portions of the fuel handling system. The containment for each unit is the third and final barrier against the possible release of radioactive material to the environment during the unlikely event of a failure of the RCS.

The Turkey Point Units 3 and 4 UFSAR classifies the containments as Class I structures designed to prevent the uncontrolled release of radioactivity. Class I structures have been determined to meet the criteria of 10 CFR 54.4 and are within the scope of license renewal. For screening, each containment was divided into two categories: containment structure and containment internal structural components. Each containment category was then subdivided into component/commodity sets to determine those structures and components requiring an AMR. The component/commodity sets were developed based on a review of Turkey Point plant-controlled drawings, the UFSAR, NAMS, and guidance from NEI 17-01 (Reference 2.4.3.1).

Note that the discussions below apply to the containments for both Units 3 and 4.

2.4.1.1 Containment Structure

Description

Each containment structure consists of a post-tensioned, reinforced-concrete cylinder and a shallow dome connected to and supported by a reinforced-concrete mat foundation. The combined strength provided by the concrete, conventional reinforcing steel, and the post-tensioning system is used to satisfy the design loads. Although these components act together as one composite system, the post-tensioning system is described as a separate component/commodity because it is installed and stressed after the reinforced components are complete and because of the unique tendon surveillance program.

Dome and Cylinder Walls - Cast-in-place concrete is used for each containment shell (cylinder wall) and mat foundation. In general, the concrete placement in the walls is done in 10-foot-high lifts with vertical joints at the radial centerline of each of the six buttresses. The dome liner plate, temporarily supported by 18 radial steel trusses and purlins, serves as the inner form for the initial 8-inch-thick pour in the dome. The weight of the remaining 21-inch dome pour is supported by the initial 8-inch pour. An 18-inch-thick cover is placed over the floor liner to protect the liner plate from punctures and corrosion that could breach the essentially leak-tight barrier.

Waterproofing membranes are used on the external surfaces of buried concrete and waterstops are embedded in the joints of buried concrete structures. Although the waterproofing membranes and waterstops help to inhibit groundwater intrusion, it is the concrete structure that protects safety-related equipment from the intrusion of groundwater. Therefore, the concrete structure is screened in because it performs the structural component intended function (i.e., provides shelter/protection to safety-related components). The waterproofing membranes and the waterstops are design features of the concrete structures; hence, they are not independently reviewed for aging effects.

Foundation Slabs - The conventionally reinforced-concrete foundation mat serves as the structural foundation support for the containment. The vertical tendons extend through the mat foundation and are anchored on the underside of the mat. A reinforced-concrete enclosure (tendon inspection gallery) is provided at the underside of the foundation mat perimeter for access to the lower vertical tendon anchorage for tendon installation and surveillance purposes. Reinforced-concrete enclosures (tendon inspection pits) are provided at the vertical buttresses for access to the lower horizontal tendon anchorage for tendon installation and surveillance.

The function of the tendon access galleries is to provide access to the bottom of the vertical tendons and to the horizontal lower tendons so they can be tested. Loss of function of the tendon access galleries is highly unlikely and to consider such is hypothetical. Per NEI 17-01 (Reference 2.4.3.1), consideration of hypothetical failures that could result from system interdependencies that are not part of the current licensing basis (CLB) and that have not been previously experienced is not required. Accordingly, the lower tendon access galleries and the inspection pits do not support the intended function of the containment structures.

Moisture barriers consisting of 1½ inch-deep sealing compound are provided between the liner air test system and concrete floors at elevation 14' to prevent intrusion of moisture between the concrete and liner surfaces.

Steel Liner Plates - The interior of each containment is lined with steel plates that are welded together. The liner plate covers the dome and cylinder walls, and also runs between the floor and the mat foundation to form an essentially leak-tight barrier. The liner helps assure leak tightness of the containment. The liner plate for the floor is placed on top of the foundation concrete pour and is covered with an additional concrete cover. The liner plate, except for the floor liner, is coated on the inside surface with inorganic zinc primer and painted for corrosion protection. The floor liner is coated on the topside with a bond breaker to allow free thermal expansion of the concrete cover.

The application of protective coatings on the liner surfaces ensures that the external metal surface is not in contact with a moist environment for extended periods of time. Although coated, no credit is taken for protective coatings applied to the liner in the determination of aging effects.

Anchors, Embedments and Attachments - Structural steel commodities include anchors, embedments, and attachments, such as angles and anchor studs, that are welded to the liner and serve to anchor each liner to the containment shells. In addition, other anchors, embedments, and attachments are provided that serve to transfer loads into the concrete cylinder walls or foundation mats from attachments to the liners.

Each liner plate is attached to the concrete by means of an angle grid system welded to the liner plate and embedded in the concrete. The anchor spacing is designed to maintain the essentially leak-tight barrier by preserving the integrity of the liner. The load-carrying capacity of these anchorages is also required to assure that supported equipment, such as the polar cranes, can perform safely as required. The polar crane bracket attachments are welded to the liner and embedded in the concrete shell.

Cathodic Protection - Structural steel components, such as the tendon trumplates, reinforcing bars, and liner plates, are interconnected to form an electrically continuous cathodic structure. Cathodic protection is a nonsafety-related design feature that does not perform intended functions as defined by 10 CFR 54.4(a). Additionally, no credit is taken for the cathodic protection system in the determination of aging effects. Accordingly, the cathodic protection system is not within the scope of SLR.

Fuel Transfer Tubes - The fuel transfer tube penetrates the containment to link the refueling canal inside the containment with the transfer canal in the spent fuel pit room in the auxiliary building. The fuel transfer tube serves as the underwater pathway for moving the fuel assemblies into and out of the containment for refueling operation during plant shutdown. As part of the containment pressure boundary, the fuel transfer tube must assure the essentially leak-tight barrier function of the containment. The fuel transfer tube gate valve provides isolation of the transfer tube on the SFP side. The fuel transfer tubes are addressed in Section 2.4.2.14 with AMR results in Section 3.5.2.

Penetrations - All containment penetrations are designed to maintain the essentially leak-tight barrier to prevent uncontrolled release of radioactivity. In addition to supporting the essentially leak-tight barrier function, each penetration performs service-related functions. Penetrations may also serve as support points for systems, such as piping passing through the containment boundary.

Mechanical Penetrations - Mechanical penetrations provide the means for passage of process piping transmitting liquids or gases across the containment boundary. The piping and ventilation penetrations are of the rigid welded type and are solidly anchored to the containment wall, thus precluding any requirement for expansion bellows.

Electrical Penetrations - Electrical penetrations provide the means for electrical and instrumentation conductors to cross the containment boundary while maintaining the essentially leak-tight barrier. Electrical penetrations consist of carbon steel pipe canisters with stainless steel or carbon steel header plates welded to each other. Each canister affords a double barrier against leakage. A flange is welded to a carbon steel sleeve penetrating the containment wall. The canister with two welded headers permits pressure and leakage tests to be performed.

Containment Equipment Hatches - The equipment hatch on each containment is a large-flanged penetration that provides access to the containment interior at the mezzanine level. A double-gasketed dished head made up of steel plate seals the opening. This head is bolted to the liner with 48 one-inch diameter bolts. A double O-ring seal, with the O-rings in grooves in the head flange, makes up the final seal. Leak tightness of the seals can be checked from outside containment by pressurizing the annular space between the two gaskets.

Containment Personnel Access Hatches - The containment personnel access hatch on each containment is a cylindrical tube that passes through the concrete wall of the containment and is welded to the steel liner. The cylinder has a door at each end, mechanically interlocked so that one door cannot be opened unless the other is closed. A mechanical interlock defeat will permit both doors to be open at the same time. The doors are the pressure-seating type, opening towards the inside of the containment.

Each door is provided with double gaskets. The door seal is made of two O-rings installed in machined grooves on the bulkhead face. The machined surface of the doorplate seals against the O-rings when the door is locked. The door locks pull the door to a metal-to-metal contact on either side of the seals, thereby compressing the O-rings.

Containment Personnel Escape Hatches - The containment personnel escape hatch on each containment is a cylindrical tube that passes through the concrete wall of the containment and is welded to the liner. The tube has a circular door opening at each end. Each door can be operated from inside and outside containment, as well as from inside the lock. A locking mechanism, which is kept under administrative control, is provided. The containment personnel escape hatch is kept locked except for entry of authorized personnel. The design of the locking mechanism allows unrestricted egress from the containment.

Post-Tensioning System - The post-tensioning system for each containment consists of numerous tendons placed around the containment walls, both vertically and horizontally, and over the containment dome. The tendons are enclosed in a sheathing system, which consists of spirally wound sheet metal tubing that acts as housing for the tendons. The tendons are installed in the sheathing system, and then tensioned to predetermined values depending on the prestress required for containment integrity.

Each containment cylinder wall is prestressed by 180 vertical tendons, anchored at the top surface of the ring girder and at the bottom of the mat foundation, and 489 hoop tendons, each enclosing 120° of arc anchored in six vertical buttresses. The dome is prestressed by three groups of 55 tendons anchored at the vertical face of the dome ring girder. Each tendon consists of 90 wires bundled together with button-headed tendon wires.

Boundary

The containment structure boundary is defined as the external surfaces of the containment structure. The containment structural boundary includes all the components that comprise the containment pressure boundary, which serves as the third and final barrier against the release of radioactive material to the environment. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Remain functional after a DBE to prevent the uncontrolled release of radioactivity.

(2) Provide structural support to safety-related components.

(3) Provide shelter/protection to safety-related components and provide a missile barrier to turbine- and tornado-generated missiles.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) The containment structures contain nonsafety-related component supports and miscellaneous steel structures, such as stairways, ladders, and platforms, which could potentially affect the satisfactory accomplishment of safety-related functions.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection.

(2) Maintain containment integrity during the duration of an SBO.

(3) House and/or support components relied on for PTS, ATWS, and SBO.

UFSAR References

Section 5.1
Appendix 5B
Appendix 5D
Section 6.6
Section 6.6.2.1
Section 6.6.3

Components Subject to AMR

Table 2.4.1-1 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-1 provides the results of the AMR.

2.4.1.2 Containment Internal Structural Components

Description

The internal structural components for each containment consist mainly of the reactor primary shield wall, the lower secondary compartments, the upper secondary compartments, the refueling cavity, RCS supports, and miscellaneous raceway, piping, and component supports.

The primary shield walls are thick cylindrical walls that enclose the reactor vessels and provide biological shielding and structural support. The primary shield walls also act as part of the missile barrier. The lower secondary compartments for each containment enclose the reactor coolant loops and consist of the secondary shield walls that support the intermediate floor. The upper secondary compartments for each containment consist of four compartments. Three of these compartments enclose one reactor coolant loop each and another encloses the pressurizer. The compartment walls provide secondary biological shielding and structural support for the operating floor.

The refueling cavity/refueling canal for each containment is a stainless-steel-lined, reinforced-concrete structure that forms a pool above the reactor when it is filled with borated water for refueling. It is irregularly shaped, formed by the upper portions of the primary shield wall and other sidewalls of varying thickness, and contains space for storing the upper and lower internals packages and miscellaneous refueling tools. During refueling operations the reactor vessel flange is sealed to the bottom of the refueling cavity by a clamped, gasketed seal ring that prevents leakage of refueling water from the cavity.

Barriers surround all high-pressure equipment, i.e., high-energy RCS piping and components, which could generate missiles as a result of a DBA. These barriers, principally the primary and secondary shield walls, prevent such missiles from damaging the containment liner, piping penetrations, and the required engineered safeguards systems. A removable reinforced-concrete shield located above the reactor vessel head to block any missile that could be generated by the CRDM provides missile protection above the reactor vessel.

Concrete walls, floors, beams, equipment pads, and other miscellaneous concrete components are of conventional design using intermediate grade reinforcing steel.

Containment Sumps – For each containment there are two containment recirculation sumps, each with a line that leads from the containment to the RHR pumps. Following a LOCA, the pumps take suction on the sumps and deliver spilled reactor coolant and borated refueling water back to the core through the RHR heat exchangers.

Sump strainers are installed in both Units 3 and 4 for the recirculation sumps. The Unit 3 sump strainer system consists of multiple expansion joints and sump strainer modules in series. Piping from the sump strainer modules feeds both the north and south recirculation sumps. Unit 4 is designed with parallel sump strainer assemblies. Piping from the strainer assemblies is routed through a plenum that then feeds both the north and south recirculation sumps. Scoping and screening of the sump strainer assemblies and associated piping are addressed with the RHRS (Section 2.3.2.5).

Steel Commodities – Structural and miscellaneous steel is provided in the containment structure to allow access to the various elevations and areas inside the containment for inspection and maintenance. The steel also provides support for several nuclear safety-related and nonsafety-related components, miscellaneous equipment supports, electrical cable tray and conduit supports, instrument supports, electrical and instrumentation enclosures and racks, miscellaneous steel beams and columns, stairways, ladders, and attachments to the concrete walls and liner. Steel commodities also include Class 1 component supports beyond those specifically identified for RCS components.

Boundary

The internal containment structure boundaries are defined as the external surfaces of the internal containment structures. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide structural support to safety-related components.

(2) Provide shelter/protection to safety-related components and provide a missile barrier.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) The containment internal structures contain nonsafety-related component supports and miscellaneous steel structures that could potentially affect the satisfactory accomplishment of safety-related functions.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

(2) House and/or support components relied on for ATWS and SBO.

UFSAR References

Section 5.1.8
Section 5.1.9
Section 11.2.2

Components Subject to AMR

Table 2.4.1-1 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-1: provides the results of the AMR.

Table 2.4.1-1
Containment Structure and Containment Internal Structural Components
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage components (post-tensioning system)	Structural support
Anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation	Structural support
ASME Class 1, 2, and 3 supports	Structural support
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support
Cable tray and conduits	Structural support
Constant and variable load spring hangers, guides, stops	Structural support
Containment structure hatches and accessories	Pressure boundary Fire barrier
Electrical instrument panels, enclosures and cabinets	Structural support Shelter, protection
Internal structural steel components	Structural support
Liner plate	Pressure boundary Fire barrier
Liner plate moisture barrier (sealing compound)	Shelter, protection
Liner plate, anchors and attachments (accessible areas)	Pressure boundary Structural support
Liner plate, anchors and attachments (inaccessible areas)	Pressure boundary Structural support
Liner plate, anchors and attachments	Pressure boundary Structural support
NaTB sump fluid pH control basket	Structural support
Penetration sleeves	Pressure boundary
Pressure-retaining bolting	Pressure boundary Fire barrier
Radiant energy shields	Fire barrier

Table 2.4.1-1
Containment Structure and Containment Internal Structural Components
Components Subject to Aging Management Review (Continued)

Component Type	Component Intended Function(s)
Reinforced concrete containment structure (accessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier
Reinforced concrete containment structure (inaccessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier
Reinforced concrete internal structural components (accessible)	Structural support Shelter, protection Missile barrier Shielding
Seals and gaskets	Pressure boundary
Service Level I coatings	Shelter, protection
Sliding surfaces	Structural support
Structural bolting	Structural support
Structural bolting: ASME Class 1, 2, and 3 supports	Structural support
Supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components	Structural support
Supports for platforms, pipe whip restraints, masonry walls, and other miscellaneous structures	HELB shielding Pipe whip restraint Structural support
Tendons (post-tensioning system)	Structural support
Vibration isolation elements	Structural support

2.4.2 Non-Containment Structures

The following structures are addressed in this section:

- Auxiliary Building (2.4.2.1)
- Cold Chemistry Laboratory (2.4.2.2)
- Control Building (2.4.2.3)
- Cooling Water Canals (2.4.2.4)
- Diesel Driven Fire Pump Enclosure (2.4.2.5)
- Discharge Structure (2.4.2.6)
- Electrical Penetration Rooms (2.4.2.7)
- Emergency Diesel Generator Buildings (2.4.2.8)
- Fire Rated Assemblies (2.4.2.9)
- Intake Structure (2.4.2.10)
- Main Steam and Feedwater Platforms (2.4.2.11)
- Plant Vent Stack (2.4.2.12)
- Polar Cranes (2.4.2.13)
- Spent Fuel Storage and Handling (2.4.2.14)
- Turbine Building (2.4.2.15)
- Turbine Gantry Cranes (2.4.2.16)
- Yard Structures (2.4.2.17)

2.4.2.1 Auxiliary Building

Description

The auxiliary building houses Class I systems and has been designed and constructed to Class I requirements. Failure of the auxiliary building, or certain portions thereof, to adequately resist the applicable design loads could result in adverse interactions with equipment and systems important to nuclear safety.

The building is constructed on a foundation mat with concrete bearing walls and slabs. Earthquake, wind and other appropriate lateral loads are resisted by diaphragm action of the walls and slabs. Ductile behavior of all the walls and slabs is maintained for better resistance of dynamic loads. Other structural elements include the roof system, structural steel framing and support members, exterior doors, isolation joints, flood protection stop logs, drains and drain plugs (stored), reinforced-concrete walls and floors, and masonry block walls. Mitigating features such as drains and drain plugs (stored) are credited for flood protection.

The building includes several areas that contain safety-related equipment (e.g., RHR pump rooms, radioactive pipeway, electrical equipment room, CS pump rooms, etc.).

Boundary

The auxiliary building evaluation boundaries are the exterior surfaces of the structure. There are no significant differences between these boundaries and the boundaries identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide shelter/protection of safety-related components inside the building from elements of the outside environment (including externally generated missiles and external flooding).

(2) Provide structural support for safety-related components located within the building.

(3) Provide protection against steam jet effects, which could result from the rupture of high-pressure piping within the building.

(4) Provide protection against the effects of flooding in the rooms housing safety-related components.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

(2) Provide protection against the effect of external flooding.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

(2) Houses and/or supports components relied on for SBO.

UFSAR References

Section 5.2

Components Subject to AMR

Table 2.4.2-1 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-2 provides the results of the AMR.

Table 2.4.2-1
Auxiliary Building Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[3]	Structural support
Concrete commodities[4]	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support
Masonry block walls	Structural support Shelter, protection Fire barrier Flood barrier
Miscellaneous steel supports and steel commodities[5]	HELB shielding Missile barrier[1] Pipe whip restraint Shelter, protection Structural support
Monorails	Structural support
Pipe trench penetration seals	Flood barrier
Stop logs, drains and drain plugs (stored)	Flood barrier
Weatherproofing[2]	Shelter, protection

Notes for Table 2.4.2-1

1. Some grating performs missile barrier function.
2. Weatherproofing component includes seals other than fire barrier, pipe trench, control building, and containment penetration seals.
3. Anchorage/embedment component includes structural bolting other than bolting considered part of load handling structure component types.
4. Concrete commodities component type includes foundations, trenches, beams, columns, walls, floors, and roof, as well as curbs and pedestals.
5. Miscellaneous steel supports and steel commodities include electrical component supports, mechanical component supports, structural steel, stairs, platforms, grating, etc.

2.4.2.2 Cold Chemistry Laboratory

Description

The cold chemistry laboratory is a concrete building with a concrete roof. It is located southwest of the turbine building. The cold chemistry laboratory does not perform any safety-related functions, or directly protect safety-related equipment.

Boundary

The cold chemistry lab evaluation boundaries are the exterior surfaces of the structure, excluding the turbine building. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Structurally designed to Class 1 requirements to prevent interaction with safety-related components.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) None.

UFSAR References

None.

Components Subject to AMR

Table 2.4.2-2 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-3 provides the results of the AMR.

Table 2.4.2-2
Cold Chemistry Laboratory Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete commodities[1]	Structural support

Notes for Table 2.4.2-2

1. Concrete commodities component type includes foundations walls, floors, and roof.

2.4.2.3 Control Building

Description

The control building is a three-story, reinforced-concrete structure housing safety-related SSCs. The control building walls and roof are designed to withstand missile effects. The control building houses the following:

- Control room.
- Cable spreading room and battery room.
- Computer room.
- Reactor control rod drive equipment and motor control centers 3B and 4B.

Boundary

The control building evaluation boundaries are the exterior surfaces of the structure. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide shelter/protection of safety-related components inside the building from elements of the outside environment (including externally generated missiles and external flooding).

(2) Provide structural support for safety-related components located within the building.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

(2) Houses and/or supports components relied on for ATWS and SBO.

UFSAR References

Section 5.3.1

Components Subject to AMR

Table 2.4.2-3 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-4 provides the results of the AMR.

Table 2.4.2-3
Control Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[2]	Structural support
Concrete commodities[3]	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support
Control room ceiling	Structural support
Control room raised floor	Structural support
Masonry block walls	Structural support Shelter, protection Fire barrier Missile barrier
Miscellaneous steel supports and steel commodities[4]	Missile barrier Shelter, protection Structural support
Penetration seals	Pressure boundary
Weatherproofing[1]	Shelter, protection

Notes for Table 2.4.2-3

1. Weatherproofing component includes seals other than fire barrier and control building penetration seals.
2. Anchorage/embedment component type includes structural bolting.
3. Concrete commodities component type includes foundations, beams, columns, walls, and floors/slabs.
4. Miscellaneous steel supports and steel commodities include electrical component supports, mechanical component supports, structural steel, stairs, platforms, grating, etc.

2.4.2.4 Cooling Water Canals

Description

The cooling water canals serve as the plant ultimate heat sink. The cooling canals constitute a closed-cooling system made up of earthen canals that provide cooling of discharged water prior to reuse at the intake structure. Structural failure of the cooling canals could impact safety-related equipment.

Boundary

The cooling canals evaluation boundaries are the exterior surfaces of the structure. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Proper function of the canals is required for the ICW system to perform its nuclear safety-related function.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

(2) Supports components relied on for SBO.

UFSAR References

None.

Components Subject to AMR

Table 2.4.2-4 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-5 provides the results of the AMR.

Table 2.4.2-4
Cooling Water Canals Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Earthen canal	Heat sink

2.4.2.5 Diesel-Driven Fire Pump Enclosure

<u>Description</u>

The diesel-driven fire pump is protected from the external environment by a prefabricated enclosure. The enclosure is designed in accordance with the South Florida Building Code. The structure is anchor bolted to a reinforced-concrete foundation. Access is provided through double doors at both ends of the building.

<u>Boundary</u>

The evaluation boundary of the diesel-driven fire pump enclosure is the exterior surface of the structure. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

<u>Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) None.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

<u>UFSAR References</u>

None.

<u>Components Subject to AMR</u>

Table 2.4.2-5 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-6 provides the results of the AMR.

Table 2.4.2-5
Diesel-Driven Fire Pump Enclosure
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[1]	Structural support
Concrete commodities[2]	Structural support
Doors	Shelter, protection
Louvers	Shelter, protection
Manufactured structure	Shelter, protection
Miscellaneous steel supports and steel commodities[3]	Structural support

Notes for Table 2.4.2-5

1. Anchorage/embedment component type includes structural bolting.
2. Concrete commodities component type includes foundations.
3. Miscellaneous steel supports and steel commodities include mechanical component supports, etc.

2.4.2.6 Discharge Structure

Description

Engineering features located along the west edge of the plant protected area are collectively referred to as the discharge structure. The primary purpose of the discharge structure is to provide for emission of the effluent from circulating water, ICW, screen wash, and storm drains into the cooling canals.

The Unit 3 discharge structure includes a concrete seal well, north concrete headwall, south concrete headwall, and associated steel framing and platforms. The seal well introduces flow from the buried circulating water piping into the cooling canals. The concrete seal well also provides a base on which structural steel framing and platforms are supported. The north headwall introduces flow from the safety-related ICW piping and nonsafety-related screen refuse and storm drain piping. The south headwall introduces flow from the nonsafety-related ICW piping.

The Unit 4 discharge structure includes a concrete seal well, south concrete headwall, and associated steel framing and platforms. The seal well introduces flow from the buried circulating water piping into the cooling water canals. The concrete seal well also provides a base on which structural steel framing and platforms are supported. The south headwall introduces flow from the safety-related ICW piping and the nonsafety-related ICW and storm drain piping. Unit 4 does not require a north headwall since the screen refuse piping is common to both units and is part of the Unit 3 north concrete head wall.

The primary function of the headwalls is to protect the embankment from currents introduced by the discharge water. While the discharge structure performs no nuclear safety-related function, the safety-related ICW piping penetrates the concrete headwall. Failure of the ICW piping concrete headwall could jeopardize the safety function of ICW.

Boundary

The discharge structure evaluation boundary includes the engineering features located along the west edge of the plant secured area. The Unit 3 discharge structure evaluation boundary includes a concrete seal well, north concrete headwall, south concrete headwall, and associated steel framing and platforms. The Unit 4 discharge structure evaluation boundary includes a concrete seal well, south concrete headwall, and associated steel framing and platforms. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) The discharge structure is a nonsafety-related structure whose failure could prevent satisfactory accomplishment of required safety-related functions.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection.

(2) Supports components relied on for SBO.

UFSAR References

None.

Components Subject to AMR

Table 2.4.2-6 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-7 provides the results of the AMR.

Table 2.4.2-6
Discharge Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete commodities[1]	Structural support

Notes for Table 2.4.2-6

1. Concrete commodities component type includes concrete seal walls and pipe headwalls.

2.4.2.7 Electrical Penetration Rooms

Description

Each unit has two electrical penetration rooms. Unit 3 has a west electrical penetration room and a south electrical penetration room. Unit 4 has a west electrical penetration room and a north penetration room. All four rooms are reinforced-concrete enclosures that contain electrical containment penetrations and cables. The west rooms are independent structures located immediately west of each containment. The north and south rooms are integral with the auxiliary building and are located at the western most interface between the auxiliary building and the containment buildings.

Boundary

The penetration room evaluation boundaries are the exterior surfaces of the enclosures. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide shelter/protection of safety-related cables inside the enclosures from elements of the outside environment (including externally generated missiles).

(2) Provide structural support for safety-related components located within the structure.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection.

(2) House and/or support components relied on for ATWS and SBO.

UFSAR References

Appendix 5A
Appendix 5E

Components Subject to AMR

Table 2.4.2-7 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-8 provides the results of the AMR.

Table 2.4.2-7
Electrical Penetration Rooms Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[2]	Structural support
Concrete commodities[3]	Fire barrier Missile barrier Shelter, protection Structural support
Miscellaneous steel supports and steel commodities[4]	Shelter, protection Structural support
Weatherproofing[1]	Shelter, protection

Notes for Table 2.4.2-7

1. Weatherproofing component includes seals other than fire barrier seals.
2. Anchorage/embedment component includes structural bolting.
3. Concrete commodities component type includes foundations, walls, and roofs.
4. Miscellaneous steel supports and steel commodities include electrical component supports, mechanical component supports, structural steel, ladders, platforms, etc.

2.4.2.8 Emergency Diesel Generator Buildings

Description

The Unit 3 and Unit 4 EDG buildings are reinforced-concrete structures housing safety-related SSCs. The first floor of each building is divided into two bays, each bay containing one of the two engine-generator sets housed in the building. The EDG buildings also house components of the EDG subsystems, such as the fuel oil, starting air, lubricating oil, combustion air, and exhaust air equipment. The EDG building includes mitigating features such as stored drains and stored drain plugs which are credited for flood protection with some credited for fire protection.

The original emergency on-site ac power source for Turkey Point Units 3 and 4 consisted of two EDGs. The two original EDGs are presently identified as 3A and 3B, and are housed in the Unit 3 EDG building. In 1990 and 1991, two additional EDG units, labeled 4A and 4B, were added to the emergency power system. The Unit 4 EDG building was designed and constructed to house the additional units.

Boundary

The EDG buildings evaluation boundaries are the exterior surfaces of the structure. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide shelter/protection of safety-related components inside the buildings from elements of the outside environment (including externally generated missiles).

(2) Provide structural support for safety-related components located within the building.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

(2) Provide protection against the effects of external flooding.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

(2) House and/or support components relied on for ATWS and SBO.

UFSAR References

Section 5.3.2
Section 5.3.4

Components Subject to AMR

Table 2.4.2-8 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-9 provides the results of the AMR.

Table 2.4.2-8
Emergency Diesel Generator Buildings Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[2]	Structural support
Concrete commodities[3]	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support
Drains, drain plugs (stored)	Flood barrier
Louvers	Shelter, protection
Masonry block walls	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support
Miscellaneous steel supports and steel commodities[4]	Shelter, protection Structural support
Stairs, platforms, grating, and supports	Structural support
U4 DOST liner	Pressure boundary
Weatherproofing[1]	Shelter, protection

Notes for Table 2.4.2-8

1. Weatherproofing component includes seals other than fire barrier seals.
2. Anchorage/embedment component includes structural bolting.
3. Concrete commodities component type includes foundations, beams, columns, walls, and floors/slabs.
4. Miscellaneous steel supports and steel commodities include electrical component supports, mechanical component supports, structural steel, stairs, platforms, grating, etc.

2.4.2.9 Fire-Rated Assemblies

Description

Fire barriers are provided as part of the protection to ensure that the function of one train of redundant equipment necessary to achieve and maintain hot standby and cold shutdown conditions remain free of fire damage. Fire barriers provide a means of limiting fire travel by compartmentalization and containment. Thermolag barriers and raceway protection, structural steel fireproofing, manhole sealants and fire retardant coatings were evaluated with the fire rated assemblies. Concrete walls, floors, and ceilings were evaluated with the specific structure in which they reside. Manhole covers were evaluated with yard structures (Section 2.4.2.17) and radiant energy shields (located inside containment) were evaluated with the containments (Section 2.4.1).

Fire door assemblies prevent the spread of fire through passageways and fire barriers. Fire door assemblies protect openings in walls and partitions against the spread of fire.

Fire dampers are provided to prevent the spread of fire through HVAC penetrations. Fire dampers are evaluated with the fire protection system (Section 2.3.3.12).

Penetration seals are provided to maintain the integrity of fire barriers at barrier penetrations. Mechanical and electrical penetrations in walls or floors made of concrete or concrete blocks are properly sealed using details provided in plant procedures.

A conduit seal is provided for an open-ended conduit if the configuration of the conduit is such that water can be conducted into equipment containing electrical terminations, and for open-ended conduits in fire areas protected by Halon suppression if the conduit penetrates a boundary of the fire area. Conduits made of polyvinyl chloride (PVC) that penetrate concrete walls of manholes are sealed using details provided in plant procedures. Conduit seals are also provided for conduits penetrating fire barriers as appropriate.

Boundary

The evaluation boundary for a fire-rated assembly is the external surface of that assembly. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

The plant is divided into fire zones, which are grouped into fire areas that are separated from each other with fire barriers. These fire barriers and associated assemblies exist throughout the power block. The locations of specific fire zones, fire areas, fire barriers, and assemblies are shown on the plant fire protection drawings. Concrete fire barriers are screened with the structure in which they reside.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide shelter/protection of safety-related components inside the enclosures from elements of the outside environment (including externally generated missiles).

(2) Fire doors integral to the environmental envelope for the Unit 3 and Unit 4 control room are classified safety-related. Control room floor penetrations are required to maintain a control room leakage boundary.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) None.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

UFSAR References

Section 9.6.1

Components Subject to AMR

Table 2.4.2-9 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-10 provides the results of the AMR.

Table 2.4.2-9
Fire Rated Assemblies Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Drip shields over Thermolag	Fire barrier
Electrical fireproofing protection	Fire barrier
Fire doors	Fire barrier Pressure boundary Shelter, protection
Fire-retardant coating	Fire barrier
Fire-sealed isolation joint	Fire barrier Flood barrier
Penetration seals	Fire barrier Flood barrier
Seals and gaskets	Fire barrier
Structural steel fireproofing	Fire barrier

2.4.2.10 Intake Structure

Description

The intake structure is a reinforced-concrete and steel structure consisting of eight intake channels (bays). The intake structure supports the six safety-related ICW pumps, the eight nonsafety-related circulating water pumps, and the three nonsafety-related screen wash pumps. These pumps take suction from the intake channels and supply water to Turkey Point Units 3 and 4. The intake structure also supports and houses the intake structure bridge crane.

At the inlet to each channel, a stationary screen collects large debris to prevent damage to the traveling screens. There are eight traveling screens, one for each intake channel, located just downstream of the stationary screens. The traveling screens remove small debris from the intake water, thus preventing debris from reaching the suction of the pumps.

Boundary

The intake structure evaluation boundaries are the exterior surfaces of the structure. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provides structural support for safety-related components located within the structure.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

(2) Provide protection against the effects of external flooding.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection.

(2) Houses and/or supports components relied on for SBO.

UFSAR References

Section 5.3

Components Subject to AMR

Table 2.4.2-10 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-11 provides the results of the AMR.

Table 2.4.2-10
Intake Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[1]	Structural support
Concrete commodities[2]	Structural support
Intake Structure Cranes (trolley frames, truck bridges)	Structural support
ICW Valve Pit rigging beam	Structural support
Intake Structure Traveling Screen (cloth, frames)	Filter Structural support
Masonry block walls	Flood barrier
Miscellaneous steel supports and steel commodities[3]	Structural support Shelter, protection

Notes for Table 2.4.2-10

1. Anchorage/embedment component includes structural bolting other than bolting considered part of load handling structures.
2. Concrete commodities include reinforced concrete foundations, beams, columns, walls, and floors/slabs (above and below intake canal level).
3. Miscellaneous steel supports and steel commodities include electrical component supports, structural steel, stairs, platforms, grating, etc.

2.4.2.11 Main Steam and Feedwater Platforms

Description

The main stream and feedwater platforms are steel and concrete structures that contain safety-related SSCs from the main steam, feedwater, and AFW systems located just outside containment. The main steam platforms are located directly west of the Unit 3 and 4 containment buildings. The feedwater platforms are located northwest of the Unit 3 containment and southwest of the Unit 4 containment. The main steam platforms contain the steam dump to atmosphere valves, MSIVs, main steam safety valves, and the steam supply to AFW pump turbines. The feedwater platforms contain the main feedwater FCVs, the feedwater air-operated check valves, the main feedwater control outlet isolation valves, and the AFW supply heater tie-ins to the main feedwater lines.

Boundary

The main steam and feedwater platform evaluation boundaries are the exterior surface of the structure. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide structural support for safety-related components located within the structure.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection.

(2) House and/or support components relied on for ATWS and SBO.

UFSAR References

None.

Components Subject to AMR

Table 2.4.2-11 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-12 provides the results of the AMR.

Table 2.4.2-11
Main Steam and Feedwater Platforms Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[1]	Structural support
Concrete commodities[2]	Missile barrier Shelter, protection Structural support
Miscellaneous steel supports and steel commodities[3]	HELB shielding Missile barrier Pressure boundary Pipe whip restraint Shelter, protection Structural support
Monorails	Structural support

<u>Notes for Table 2.4.2-11</u>

1. Anchorage/embedment component includes structural bolting other than bolting considered part of load handling structures.
2. Concrete commodities include foundations, walls, floors, and roof, as well as curbs and drains.
3. Miscellaneous steel supports and steel commodities include electrical component supports, mechanical component supports, structural steel, stairs, platforms, grating, etc.

2.4.2.12 Plant Vent Stack

Description

The plant vent stack is a steel tubular structure used for releasing processed gases to the atmosphere. The stack is supported at its base by the auxiliary building roof and laterally restrained near its top by the Unit 4 containment structure. Structural failure of the stack could impact safety-related equipment.

Boundary

The plant vent stack evaluation boundary includes the vent stack and its supporting structural members up to and including the anchor bolts. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) None.

UFSAR References

Section 9.8

Components Subject to AMR

Table 2.4.2-12 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-13 provides the results of the AMR.

Table 2.4.2-12
Plant Vent Stack Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[1]	Structural support
Concrete commodities[2]	Structural support
Miscellaneous steel supports and steel commodities[3]	Structural support
Steel vent stack	Gaseous release path Structural support

Notes for Table 2.4.2-12

1. Anchorage/embedment component includes structural bolting other than bolting associated with load handling structures.
2. Concrete commodities include concrete pedestal and grout cover.
3. Miscellaneous steel supports and steel commodities include electrical component supports, structural steel, etc.

2.4.2.13 Polar Cranes

Description

The reactor (reactor building or containment) polar cranes and associated rails are seismically qualified Class I structures in the unloaded configuration. The cranes provide a means for lifting and handling heavy loads inside the containment structures. The containment polar cranes and associated rail supports are enclosed by the containment structure, which is designed to withstand impact of all missiles. The reactor polar cranes are part of the safe load paths for heavy load handling systems.

Boundary

The Unit 3 reactor polar crane is located in the Unit 3 containment building, and the Unit 4 reactor polar crane is located within the Unit 4 containment building. The polar crane evaluation boundary within containment includes the reactor polar crane and associated rails. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide a safe means for lifting and handling heavy loads within the containment structure.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) None.

UFSAR References

Section 5A
Section 5I

Components Subject to AMR

Table 2.4.2-13 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-14 provides the results of the AMR.

Table 2.4.2-13
Polar Cranes Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Cab	Structural support
End connectors (fasteners)[1]	Structural support
Footwalks and railings	Structural support
Main girders	Structural support
Miscellaneous steel supports and steel commodities[2]	Structural support
Runway rails, runway rail brackets, trolley rails, trolley structure	Structural support

Notes for Table 2.4.2-13

1. End connectors (fasteners) component includes structural bolting
2. Miscellaneous steel supports and steel commodities include electrical component supports, etc.

2.4.2.14 Spent Fuel Storage and Handling

Description

Spent fuel handling includes all the equipment and tools necessary to remove spent fuel from the reactor vessel, transport spent fuel to the spent fuel pit, place spent fuel in the appropriate storage rack cell, and remove spent fuel from the spent fuel storage pit for alternative storage. The major equipment required for spent fuel handling includes: the reactor cavity seal ring, the manipulator crane (inside containment), the fuel transfer system (located in the refueling canal inside containment and in the fuel transfer canal in the spent fuel building), the fuel transfer tube, the spent fuel bridge crane, the fuel handling tools, and the spent fuel cask crane.

Spent fuel storage includes all the structural components necessary to store spent fuel in the spent fuel storage pit, excluding the concrete structure. The major structural items required for spent fuel storage are the spent fuel pit liner, the keyway gate, and the spent fuel storage racks. The concrete fuel handling building (including the spent fuel pit and the concrete sliding door) is part of the auxiliary building and is screened with the rest of the auxiliary building structure in Section 2.4.2.1.

The spent fuel storage pits are designed for the underwater storage of spent fuel assemblies and control rods after removal from the reactor. The spent fuel pits are lined on the interior surface with a stainless steel liner plate. Stainless steel storage racks sitting on the pit floor are provided to hold spent fuel assemblies. Fuel assemblies are placed in vertical cells and are held in a rectangular high-density array. The racks are designed so that it is impossible to insert fuel assemblies in other than the prescribed locations, thereby ensuring the necessary spacing between assemblies. The high-density stainless steel storage racks utilize Metamic inserts, which contain a neutron absorbing material.

Boundary

The spent fuel storage and handling equipment evaluation boundary includes the spent fuel pit area, the transfer canal, the refueling canal, and the reactor cavity. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide pressure boundary.

(2) Provide shelter/protection of safety-related components inside the enclosures from elements of the outside environment (including externally generated missiles).

(3) Provide structural support for safety-related components located within the structure.

(4) Prevent criticality of fuel assemblies stored in the SFP.

(5) Store spent fuel without damage to fuel assemblies.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) None.

UFSAR References

Section 5.2.4
Section 9.5

Components Subject to AMR

Table 2.4.2-14 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-15 provides the results of the AMR.

Table 2.4.2-14
Spent Fuel Storage and Handling Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete commodities[1]	Fire barrier[3] Missile barrier[3] Shelter, protection
Cranes (reactor cavity manipulator crane, spent fuel bridge crane, and spent fuel cask crane) and bolting	Structural support
Fuel assembly transfer machine/system	Structural support
Fuel transfer tube and sleeve	Pressure boundary Structural support
Miscellaneous steel supports and steel commodities[2]	Structural support
Reactor cavity seal ring	Pressure boundary
Spent Fuel Pool keyway gate	Pressure boundary
Spent fuel storage rack inserts	Absorb neutrons
Spent fuel storage racks	Structural support
Stainless steel liners	Pressure boundary

Notes for Table 2.4.2-14

1. Concrete commodities component type includes overhead concrete door
2. Miscellaneous steel supports and steel commodities include: handling tools, new fuel storage components, etc.
3. Intended function is applicable for the overhead concrete door.

2.4.2.15 Turbine Building

Description

The turbine building is primarily an open steel frame built on reinforced-concrete mat foundations. The reinforced-concrete turbine pedestals are the dominant structural features of the turbine building. The building is essentially rectangular in shape with the long north/south axis sharing the Unit 3 and 4 turbine centerline orientation. The building is located just west of the Unit 3 and Unit 4 reactor buildings. The ground floor is surrounded by a floodwall to protect turbine building equipment. In addition to the nonsafety-related steam turbines, electric generators, condensers, heaters, and related equipment, the turbine building also houses safety-related equipment. The turbine building also includes mitigating features such as drains and drain plugs (stored) which are credited for flood protection.

The turbine building houses the following the Units 3 and 4 safety-related equipment and structures: 4160V switchgear, 480V load center and associated concrete enclosures; the 3A and 4A MCCs and associated steel enclosures, and the ICW piping and isolation valves at the inlet to the TPCW heat exchangers and associated structures. In addition, the following miscellaneous safety-related equipment is included in the turbine building: the AFW supply lines from the CSTs, miscellaneous electrical raceway and instrumentation, and numerous conduits and cable trays.

Boundary

The turbine building evaluation boundary is the exterior surface of the structure. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide shelter/protection of safety-related components from elements of the outside environment (including externally generated missiles).

(2) Provide structural support for safety-related components located within the structure.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

(2) Provide protection against the effects of external flooding.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection.

(2) House and/or support components relied on for ATWS and SBO.

UFSAR References

Section 5.3.2
Appendix 5A

Components Subject to AMR

Table 2.4.2-15 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-16 provides the results of the AMR.

Table 2.4.2-15
Turbine Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[2]	Structural support
Concrete commodities[3]	Fire barrier Shelter, protection Structural support
Drains and drain plugs (stored)	Flood barrier
Flood seals for pipe trench (Promatec flexible pressure seals)	Flood barrier
Masonry block walls	Fire barrier Flood barrier Shelter, protection Structural support
Miscellaneous steel supports and steel commodities[4]	HELB shielding Missile barrier Pressure boundary Pipe whip restraint Shelter, protection Structural support
Stop logs	Flood barrier
Weatherproofing[1]	Shelter, protection

<u>Notes for Table 2.4.2-15</u>

1. Weatherproofing component includes seals other than fire barrier seals and pipe trench flood seals.
2. Anchorage/embedment component includes structural bolting.
3. Concrete commodities component type includes foundations, walls, floors, and roof (switchgear/ load center enclosures), curbs and drains.
4. Miscellaneous steel supports and steel commodities include electrical component supports, mechanical component supports, structural steel, stairs, platforms, grating, etc.

2.4.2.16 Turbine Gantry Cranes

Description

The Turkey Point Fossil Units 1 and 2 turbine gantry crane has a rated capacity of 70/15 tons. The Turkey Point Nuclear Units 3 and 4 turbine gantry crane has a rated capacity of 170/35 tons. The two turbine gantry cranes share rails common to all four units. The Units 1 and 2 turbine gantry crane is used almost exclusively on Units 1 and 2, and the Units 3 and 4 turbine gantry crane is used almost exclusively on Units 3 and 4. Although infrequent, when the Units 1 and 2 turbine gantry crane is used on Units 3 and 4, an evaluation is performed to ensure conformance with NUREG-0612 as described in UFSAR Appendix 5I.

Boundary

The Units 3 and 4 turbine gantry crane is located on the operating deck of the turbine building. The Turkey Point Fossil Units 1 and 2 turbine gantry crane and the Turkey Point Nuclear Units 3 and 4 turbine gantry crane share rails common to all four units. The evaluation boundary includes the gantry crane and associated rails. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) The turbine gantry cranes are nonsafety-related structures whose failure could prevent satisfactory accomplishment of required safety-related functions.

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

(1) None.

UFSAR References

Appendix 5I

Components Subject to AMR

Table 2.4.2-16 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-17 provides the results of the AMR.

Table 2.4.2-16
Turbine Gantry Cranes Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Cab	Structural support
Miscellaneous steel supports and steel commodities[1]	Structural support
Monorails	Structural support
Rail anchorage/embedment	Structural support
Runway rails, runway rail brackets, trolley rails, and trolley structure	Structural support

Notes for Table 2.4.2-16

1. Miscellaneous steel supports and steel commodities components include electrical component supports, ladders, platforms, structural steel, etc.

2.4.2.17 Yard Structures

Description

Yard structures includes concrete foundations for miscellaneous SLR in-scope equipment and structures, concrete trenches for in-scope piping and utilities, and concrete duct banks and electrical manholes for in-scope electrical systems that are not included within an existing in-scope structure. Steel support structures (e. g., yard pipe supports) associated with the above described concrete structures were evaluated with the associated system.

Boundary

The evaluation boundary of each yard structure is the exterior surface of the structure. For trenches and duct banks, the structure boundaries shall terminate at the point they enter separate structures (e.g., building or manhole). Also, consistent with SLR scoping requirements, the structural components in the switchyard associated with restoration of offsite power following an SBO are in the scope of SLR. There are no significant differences between the current boundaries and those identified as part of the original Turkey Point license renewal effort.

Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide shelter/protection of safety-related components inside the enclosures from elements of the outside environment (including externally generated missiles).

(2) Provide structural support to safety-related components.

(3) Provide pipe whip restraint and/or jet impingement protection.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support to nonsafety-related components to preclude interactions with safety-related components.

(2) Provide protection against the effect of external flooding

Fire protection, EQ, PTS, ATWS, SBO functions (10 CFR 54.4(a)(3)):

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

(2) House and/or support components relied on for ATWS and SBO.

UFSAR References

None.

Components Subject to AMR

Table 2.4.2-17 lists the component types that require AMR and their associated component intended functions.

Table 3.5.2-18 provides the results of the AMR.

Table 2.4.2-17
Yard Structures Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage/embedment[1]	Structural support
Berm (embankment)	Flood barrier
Concrete commodities[2]	Shelter, protection Structural support
Drains and drain plugs (stored)	Flood barrier
Masonry block walls	Flood barrier
Miscellaneous steel supports and steel commodities[3]	Pipe whip restraint Shelter, protection Structural support
Ramp (paved)	Flood barrier
Stop logs	Flood barrier
TPCW basket strainer monorails	Structural support
Transmission towers	Structural support

Notes for Table 2.4.2-17

1. Anchorage/embedment component includes structural bolting other than bolting considered part of load handling structures.
2. Concrete commodities component type includes foundations, duct banks, manholes, storm drains, etc.
3. Miscellaneous steel supports and steel commodities include electrical component supports, mechanical component supports, etc.

2.4.3 References

2.4.3.1 NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal," March 2017.

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION AND CONTROLS

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.

The methodology used in identifying electrical and I&C components requiring an AMR is discussed in Section 2.1.6.3. The screening for electrical and I&C components was performed on a generic component commodity group basis for the in-scope electrical and I&C systems listed in Table 2.2-3, as well as the electrical and I&C component commodity groups associated with in-scope mechanical systems and civil structures listed in Tables 2.2-1 and 2.2-2. The methodology employed is consistent with the guidance in NEI 17-01 (Reference 2.5.3.1).

The interface of electrical and I&C components with other types of components and the assessments of these interfacing components are provided in the appropriate mechanical or structural sections. For example, the assessment of electrical racks, panels, frames, cabinets, cable trays, conduits, and their supports is provided in the structural assessment documented in Sections 2.4 and 3.5.

The electrical and I&C components included in the screening were the separate electrical and I&C components that were not parts of larger components. For example, the wiring, terminal blocks, and connections located internal to a breaker cubicle were considered to be parts of the breaker. Accordingly, the breaker was screened, but not the internal parts of the breaker.

2.5.1 Electrical and I&C Component Commodity Groups

2.5.1.1 Identification of Electrical and I&C Components

The electrical and I&C component commodity groups were identified from a review of drawings controlled, NAMS, and interface with parallel mechanical and structural screening efforts. This commodity based approach, whereby component types with similar design and/or functional characteristics are grouped together, is consistent with guidance from NEI 17-01 (Reference 2.5.3.1) and Table 2.1-6 of NUREG-2192 (Reference 2.5.3.2). The in-scope electrical and I&C component commodity groups identified at Turkey Point Units 3 and 4 are listed in Table 2.5-1.

2.5.1.2 Application of Screening Criterion 10 CFR 54.21(a)(1)(i) to the Electrical and I&C Components and Commodities

Following the identification of the electrical components and commodity groups, the criterion of 10 CFR 54.21(a)(1)(i) is applied to identify electrical commodity groups that perform their functions without moving parts or without a change in configuration or properties. The following electrical commodity groups meet the screening criteria of 10 CFR 54.21(a)(1)(i) for Turkey Point:

- Insulated cables and connections
- Electrical and I&C penetration assemblies
- High voltage insulators
- Switchyard bus
- Transmission conductors
- Uninsulated ground conductors

2.5.1.3 Elimination of Electrical and I&C Commodity Groups not Applicable to Turkey Point

The following electrical and I&C commodity groups are not applicable to Turkey Point:

Cable Tie-Wraps

At Turkey Point, cable fasteners and tie-wraps are intended to be used for training cables, assembling wires or cables into neat bundles and for general housekeeping purposes. They are not considered a cable support. Electrical cable tie-wraps do not function as cable supports in raceway support analyses; therefore, the installation and inspection criteria is limited to the application of standard practices in providing quality cable bundles and cable placement. Seismic qualification of cable trays does not credit the use of electrical cable tie-wraps. Cable tie-wraps have no SLR intended functions as defined in 10 CFR 54.4(a). Since cable tie-wraps do not have a SLR intended function, they are not subject to an AMR.

Fuse Holders (Metallic Clamps)

The cables and connections commodity group includes fuse holders (fuse blocks).

Consistent with NUREG-2191, XI.E5, *Fuse Holders,* the screening of fuse holders (metallic clamps) applies to those that are not part of a larger (active) assembly. Fuse holders inside the enclosure of an active component, such as switchgear, power supplies, power inverters, battery chargers, and circuit boards are considered piece parts of the larger assembly. Since piece parts and subcomponents in such an enclosure are routinely inspected and regularly maintained as part of the plant's normal maintenance and surveillance activities, they are not subject to AMR (Reference 2.5.3.3).

Prior to entering into the period of extended operation (PEO), a readiness assessment was conducted by performing a gap analysis with respect to fuse holders (NUREG-1801, Revision 2, Section XI.E5). This assessment is documented in the corrective action system. The gap analysis included a design review of the fuse list and determined that there are no fuses that support a system-level intended function that are not part of an active component, such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. This evaluation also determined that fuses are located in benign areas, such as the Control Room, Cable Spreading Room, Switchgear Rooms, EDG Rooms, New Equipment Room, etc. These benign environments or operating conditions preclude aging effects caused by stressors (e.g., fuse holders not subject to vibration from rotating machinery). Thus fuses, including metallic clamps for the fuse clips of the fuse holders, are considered piece parts of a larger active assembly and are thereby not subject to AMR.

Metal Enclosed Bus

Metal enclosed bus (e.g., isolated-phase bus, non-segregated-phase bus, and segregated-phase bus) are not utilized in the restoration power path for offsite power following a SBO event or otherwise relied on to meet the SLR scoping requirements of 10 CFR 54.4(a).

Cable bus is a variation on metal enclosed bus, which is similar in construction to a metal enclosed bus, but instead of segregated or non-segregated 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, or ice and, therefore, may introduce debris into the internal cable bus assembly. Cable bus is not utilized at Turkey Point in the restoration power path for offsite power following a SBO event or otherwise relied on to meet the SLR scoping requirements of 10 CFR 54.4(a).

2.5.1.4 Application of Screening Criteria 10 CFR 54.21(a)(1)(ii) to Electrical and I&C Commodity Groups

The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to the specific commodities that remained following application of the 10 CFR 54.21(a)(1)(i) criterion. Criterion 10 CFR 54.21(a)(1)(ii) allows the exclusion of those commodities that are subject to replacement based on a qualified life or specified time period. The only electrical commodities identified for exclusion by the criteria of 10 CFR 54.21(a)(1)(ii) are electrical and I&C components and commodities included in the EQ Program. This is because electrical and I&C components 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 AMR in accordance with the screening criterion of 10 CFR 54.21(a)(1)(ii). Note that TLAAs associated with electrical and I&C components within the EQ Program are discussed in Section 4.4.

Insulated Cables and Connections

The function of insulated cables and connections is to electrically connect specified sections of an electrical circuit to deliver voltage, current, or signals. Electrical cables and their required terminations (i.e., connections) are reviewed as a single component commodity group. The types of connections included in this review are splices, connectors, and terminal blocks. Numerous insulated cables and connections are included in the EQ Program. The insulated cables and connections that are included in this program have a qualified life that is documented in the EQ Program. Components in the EQ Program are replaced by the end of the qualified life. Accordingly, all insulated cables and connections within the EQ Program are replacement items under 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR. Note that TLAAs associated with electrical/I&C components within the EQ Program are discussed in Section 4.4.

Insulated cables and connections that perform an intended function within the scope of SLR, but are not included in the EQ Program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

Switchyard Bus, High Voltage Insulators, Transmission Conductors

NUREG-2191, Chapter VI.A, addresses components that are relied upon to meet the SBO requirements for restoration of offsite power. This guidance is consistent with the guidance provided to the original license renewal applicants under NRC letter dated April 1, 2002 (Reference 2.5.3.4). An evaluation was performed as part of the original Turkey Point license renewal effort to determine the restoration power path for offsite power following a SBO event based on the guidance of the NRC letter. A summary of that evaluation was submitted to the NRC by FPL letter dated April 19, 2002 (Reference 2.5.3.5). Consistent with the evaluation, the switchyard commodities of switchyard bus, high-voltage insulators and transmission conductors perform an intended function for restoration of offsite power following a SBO event. Additionally, none of these commodities are included in the EQ Program. Thus, these commodities meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

Drawing 5610-E-1, sheet 1 and sheet 2 (Reference 2.5.3.6), depicts the electrical interconnection between Turkey Point Units 3 and 4 and the offsite transmission network. The highlighted portions of SLR drawing 5610-E-1, sheet 1 and sheet 2, identifies the restoration power path used for offsite power following a SBO event.

Electrical and I&C Penetration Assemblies

Electrical and I&C penetration assemblies included in the EQ Program have a qualified life that is documented. Therefore, electrical and I&C penetration assemblies in the EQ Program do not meet the criterion of 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR.

A review of the electrical and I&C penetrations determined that in addition to the electrical and I&C penetration assemblies included in the EQ Program, eleven non-EQ electrical and I&C penetration assemblies were determined to support systems and components inside containment that are in the scope of SLR. Electrical and I&C penetration assemblies that are in the scope of SLR, but not included in the EQ Program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

Uninsulated Ground Conductors

Uninsulated ground conductors are electrical and I&C conductors that are uninsulated (bare) and are used to make ground connections for electrical and I&C equipment. Uninsulated ground conductors are connected to electrical and I&C equipment housings and electrical and I&C enclosures, as well as metal structural features, such as the cable tray system and building structural steel. Uninsulated ground conductors are isolated or insulated from the electrical and I&C operating circuits.

Uninsulated ground conductors are relied upon in safety analyses and plant evaluations at Turkey Point to perform a function that demonstrates compliance with the Commission's regulations for fire protection. Uninsulated ground conductors meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

2.5.2 Electrical and I&C Commodity Groups Subject to Aging Management Review

Table 2.5-2 lists the electrical and I&C commodity groups that require AMR and their associated component intended functions.

Table 3.6.2-1 provides the results of the AMR.

2.5.3 References

2.5.3.1 NEI 17-01, Rev. 0, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal," March 2017.

2.5.3.2 NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants Final Report," United States Nuclear Regulatory Commission, ADAMS Accession No. ML16274A402.

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

2.5.3.4 "Staff Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout (SBO) Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))" (ISG-02) ML020920464.

2.5.3.5 L-2002-071, "Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, Response to NRC Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule for License Renewal" dated April 19, 2002, ADAMS Accession No. ML021230332.

2.5.3.6 SBO Drawings:
5610-E-1, Sheet 1, Main Single Line Unit 3.
5610-E-1, Sheet 2, Main Single Line Unit 4.

Table 2.5-1
Electrical and I&C Component Commodity Groups
Installed at Turkey Point for In-Scope Systems

Alarm Units	Fuses	Power Distribution Panels	Switches
Analyzers	Generators	Power Supplies	Switchgear
Annunciators	Heat Tracing	Radiation Monitors	Switchyard Bus
Batteries	High-Voltage Insulators	Recorders	Terminal Blocks
Chargers	Indicators	Regulators	Thermocouples
Circuit Breakers	Insulated Cables and Connections	Relays	Transducers
Converters	Inverters	RTDs	Transformers
Communication Equipment	Isolators	Sensors	Transmitters
Electrical Bus	Light Bulbs	Solenoid Operators	Transmission Conductors
Electrical Controls and Panel Internal Component Assemblies	Load Centers	Signal Conditioners	Uninsulated Ground Conductors
Electrical/I&C Penetration Assemblies	Meters	Solid-State Devices	
Electric Heaters	Motor Control Centers	Splices	
Elements	Motors	Surge Arresters	

Table 2.5-2
Electrical and Instrumentation and Control Systems
Components Subject to Aging Management Review

Structure and/or Component/ Commodity	Component Intended Function(s)
Insulated cables and connections not included in the EQ Program	Electrical continuity
Electrical and I&C penetration assemblies not included in the EQ Program	Electrical continuity
Switchyard bus and connections (for SBO recovery)	Electrical continuity
Transmission conductors and connections (for SBO recovery)	Electrical continuity
High voltage insulators (for SBO recovery)	Insulation (electrical)
Uninsulated ground conductors and connections	Electrical continuity

3.0 AGING MANAGEMENT REVIEW RESULTS

This section provides the results of the aging management review (AMR) for those structures and components identified in Section 2 as being subject to aging management review.

Tables 3.0-1, 3.0-2, and 3.0-3 provide descriptions of the mechanical, structural, and electrical service environments, respectively, used in the AMRs to determine aging effects requiring management. The environments used in the AMRs are listed in the Environment column. The third column identifies one or more of the NUREG-2191 environments that were used when comparing the Turkey Point AMR results to the NUREG-2191 results.

Results of the AMRs are presented in the following two table types:

Table 3.x-1 - where '3' indicates the subsequent license renewal application (SLRA) section number, 'x' indicates the Section number from NUREG-2192, and '1' indicates that this is the first table type in Section 3. For example, in the reactor coolant system section, this table would be number 3.1-1, in the engineered safety features section, this table would be 3.2-1, and so on. For ease of discussion, these tables will, hereafter, be referred to in this section as “Table 1s."

Table 3.x.2-y - where '3' indicates the SLRA section number, 'x' indicates the section 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 vessel section, this table would be Table 3.1.2-3 and for the reactor vessel internals, it would be Table 3.1.2-4. The emergency containment cooling table, within the Engineered Safety Features Section, would be Table 3.2.2-1. For ease of discussion, these tables will, hereafter, be referred to in this section as "Table 2s."

TABLE DESCRIPTION

NUREG-2191 contains the generic evaluation of existing plant programs. It documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the subsequent period of extended operation (SPEO). 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 subsequent license renewal, without change. NUREG-2191 also contains recommendations on specific areas for which existing programs should be augmented for subsequent license renewal. In order to take full advantage of NUREG-2191, a comparison between the Turkey Point AMR results and the tables of NUREG-2191 has been performed. The results of that comparison are provided in the two tables.

Table 1s

The purpose of the Table 1s is to provide a summary comparison of how the Turkey Point AMR results align with the corresponding tables of NUREG-2192. These tables are essentially the same as Tables 3.1-1 through 3.6-1 provided in NUREG-2192, except that the “New, Modified, Deleted, Edited Item", "ID", and "Type" columns have been replaced by an "Item Number" column, and the "GALL-SLR Item" column has been replaced by a "Discussion" column.

The "Item Number" column provides the reviewer with a means to cross-reference from the Table 2s to the Table 1s.

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 management program being used, if applicable.
- Exceptions to the NUREG-2191 and 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 the Table 1s 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 2s

Table 2s provide the detailed results of the AMRs for those structures and components identified in SLRA Section 2 as being subject to aging management review. There is a Table 2 for each of the systems within a Section 3 grouping. For example, for Turkey Point, the Engineered Safety Features system group contains Table 2s specific to emergency containment cooling, containment spray, containment isolation, safety injection, residual heat removal, and containment post-accident monitoring and control.

Table 2s also provide a comparison of the AMR results with the AMR results in NUREG-2191. Comparison to NUREG-2191 is performed by considering the component type, material, environment, aging effect requiring management (AERM), and aging management program (AMP) listed in each Table 2 line item to determine the degree of consistency with an appropriate NUREG-2191 line item, if one exists. The comparison is documented in columns 7, 8, and 9, as discussed below. Table 2s consist of the following nine columns:

- Component Type
- Intended Function
- Material
- Environment
- Aging Effect Requiring Management
- Aging Management Programs

- NUREG-2191 item
- Table 1 item
- Notes

Component Type – The first column identifies all of the component types from Section 2 of the SLRA that are subject to AMR. Component types are clarified in the Table 2s to include additional detail when that detail affects what NUREG-2191 item is used. For example, “(insulated)” is added to the component type to clarify that the external environment has a layer of insulation separating the component from the air and an insulated GALL-SLR item (e.g., VIII.H.S-402a) is used rather than a non-insulated GALL-SLR item (e.g., VIII.H.S-29).

Intended Function – The second column contains the SLR structure/component intended functions for the listed structure/component types. Definitions of structure/component intended functions are contained in Table 2.1-2.

Material – The third column lists the particular materials of construction for the component type being evaluated. To determine if there are any plant modifications that have changed materials since submittal of the first license renewal application, the component database was queried to download a list of engineering changes that have been implemented on the each system from January 1, 2002, to February 1, 2017. Once this list was compiled, it was screened by title to remove engineering changes that could not affect materials. The remaining engineering changes were downloaded and reviewed to determine the impact on each AMR.

Environment – The fourth column lists the environments to which the component types are exposed. A description of these environments is provided in Tables 3.0-1, 3.0-2, and 3.0-3 for mechanical, structural, and electrical components, respectively. To determine if there are any plant modifications that have changed component environments since submittal of the first license renewal application, the component database was queried to download a list of engineering changes that have been implemented on the each system from January 1, 2002, to February 1, 2017. Once this list was compiled, it was screened by title to remove engineering changes that could not affect component environments. The remaining engineering changes were downloaded and reviewed to determine the impact on each aging management review.

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.

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 NUREG-2192 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-2192, this field in column eight is left blank. The Table 1 Item allows correlation of the information from the two tables.

Notes – The notes provided in each Table 2 describe how the information in the table aligns with the information in NUREG-2191. Each Table 2 contains standard lettered notes (e.g., A, B, C), as applicable, providing information regarding comparison of the Turkey Point AMR results with the NUREG-2191 Aging Management Table line item identified in the seventh column. In addition to the applicable standard lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

<u>TABLE USAGE</u>

Table 1s

The reviewer evaluates each row in the Table 1s by moving from left to right across the table. Since the Component, Aging Effect/Mechanism, Aging Management Program (AMP)/TLAA and Further Evaluation Recommended information is taken directly from NUREG-2192, no further analysis of those columns is required. The information of primary help to the reviewer is contained within the Discussion column. Here the reviewer will be given plant-specific information necessary to determine, in summary, how the Turkey Point evaluations and programs align with NUREG-2192, or if the item is applicable. 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 2s

The Table 2s contain all of the AMR information for the plant, whether it aligns with NUREG-2191. For a given row within the table, the reviewer is able to see the intended function, material, environment, aging effect requiring management and aging management program combination for a particular component type within a system. In addition, if there is a correlation between the combination in Table 2 and a combination in NUREG-2191, this will be identified by a referenced item number in column 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 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-2192.

As NUREG-2191 does not address all possible material, environment, and aging effect combinations in each of its chapters, table items from other chapters are used if required. For example as Chapter VIII – Steam and Power Conversion System does not contain any lines addressing thermal fatigue for stainless steel components, a stainless steel fatigue line from Chapter VII – Auxiliary Systems (VII.E1.A-57) is used. Another example is Chapter VII – Auxiliary Systems does not contain a line for loss of material in stainless steel heat exchanger components exposed to closed cycle cooling water. In this case a line from Chapter VIII – Steam and Power Conversion System (VII.G.S-25) is used. When this occurred, the EPRI Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools (Reference 1.6.17) was used to verify the aging effect and management program were applicable to the material and environment combinations and that the NUREG-2191 items used are not unique to the system parameters for their intended systems.

The Table 2s provide the reviewer with a means to navigate from the components subject to AMR in SLRA Section 2.0 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 1.7.

Table 3.0-1
Service Environments for Mechanical Aging Management Reviews

Environment	Description	Corresponding NUREG-2191 Environments
Air – dry	Air that has been treated to reduce its dew point well below the system operating temperature and treated to control lubricant content, particulate matter, and other corrosive contaminants	Air – dry
Air – indoor controlled	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment	Air – indoor controlled
Air – indoor uncontrolled	This environment is for indoor locations that are sheltered/ protected from weather. Surfaces of components in this environment may be wetted, but only rarely; equipment surfaces are normally dry.	Air – indoor uncontrolled
Air – outdoor	The outdoor environment consists of atmospheric air, salt-laden air, ambient temperature and humidity, and exposure to precipitation.	Air – outdoor
Air with borated water leakage	This environment is similar to the Air-indoor uncontrolled environment, but is used for components located within buildings that have systems containing treated borated water as they may be susceptible to borated water leakage and subsequent boric acid corrosion.	Air with borated water leakage
Concrete	Components in contact with concrete.	Concrete
Condensation	Air and condensation on surfaces of indoor systems with temperatures below dew point; condensation is considered untreated water due to potential for surface contamination.	Condensation
Diesel exhaust	Gases, fluids, particulates present in diesel engine exhaust.	Diesel exhaust
Fuel oil	Diesel oil, No. 2 oil, or other liquid hydrocarbons used to fuel diesel engines.	Fuel oil
Gas	Internal dry non-corrosive gas environment such as nitrogen, carbon dioxide, Freon, and halon.	Gas
Lubricating oil	Lubricating oils are low- to medium-viscosity hydrocarbons used for bearing, gear, and engine lubrication. An oil analysis program may be credited to preclude water contamination.	Lubricating oil

Table 3.0-1
Service Environments for Mechanical Aging Management Reviews (Continued)

Environment	Description	Corresponding NUREG-2191 Environments
Neutron flux	Neutron flux integrated over time. Neutron fluence is specified as an environment for the limiting reactor vessel components with material properties that may be significantly affected by neutron irradiation.	Neutron flux High fluence (> 1 x 10^{21} n/cm^2, E > 0.1 million electron volts (MeV))
Raw water	Water that enters the plant from the cooling water canals, ocean, bay, or city water source that has not been demineralized. In general, the water has been rough filtered to remove large particles and may contain a biocide for control of microorganisms and macro-organisms. Although city water is purified for drinking purposes, it is conservatively classified as raw water for the purposes of aging management review. As a note, the raw water in the cooling water canals has a higher saline content than local ocean or bay water	Raw water
Reactor coolant	Reactor coolant is treated water in the reactor coolant system and connected systems at or near full operating temperature. This includes wet steam in the pressurizer.	Reactor coolant
Steam	Steam, subject to a water chemistry program. In determining aging effects, steam is considered treated water.	Steam
Soil	External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to groundwater in the soil.	Soil
Treated borated water	Treated or demineralized borated water.	Treated borated water
Treated borated water > 140°F	Treated or demineralized borated water above stress corrosion cracking (SCC) threshold for stainless steel	Treated borated water > 140°F
Treated water	Treated water is demineralized water and is the base water for all clean systems.	Treated water
Treated water > 140°F	Treated water above 140°F SCC threshold for SS.	Treated water > 140°F

Table 3.0-1
Service Environments for Mechanical Aging Management Reviews (Continued)

Environment	Description	Corresponding NUREG-2191 Environments
Underground	Underground piping and tanks below grade, but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is limited. When the underground environment is cited, the term includes exposure to air–outdoor, air–indoor uncontrolled, raw water, groundwater, and condensation.	Underground
Waste water	Water in liquid waste drains such as in liquid radioactive waste systems, oily waste systems, floor drainage systems, chemical waste water systems, and secondary waste water systems. Waste waters may contain contaminants, including oil and boric acid, as well as treated water not monitored by a chemistry program.	Waste water

Table 3.0-2
Service Environments for Structural Aging Management Reviews

Environment	Description	Corresponding NUREG-2191 Environments
Air – indoor controlled	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment.	Air – indoor controlled
Air – indoor uncontrolled	This environment is for indoor locations that are sheltered/ protected from weather. Surfaces of components in this environment may be wetted, but only rarely; equipment surfaces are normally dry.	Air – indoor uncontrolled
Air – outdoor	The outdoor environment consists of atmospheric air, salt-laden air, ambient temperature and humidity, and exposure to precipitation.	Air – outdoor
Air with borated water leakage	This environment is similar to the Air-indoor uncontrolled environment, but is used for components located within buildings that have systems containing treated borated water as they may be susceptible to borated water leakage and subsequent boric acid corrosion.	Air with borated water leakage
Fuel oil	Diesel oil, No. 2 oil, or other liquid hydrocarbons used to fuel diesel engines.	Fuel oil
Groundwater	This is the external environment for structural components buried in the soil and exposed to groundwater. Groundwater is only applicable to the auxiliary building and containment building foundations.	Groundwater
Soil	External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to groundwater in the soil.	Soil
Treated borated water	Treated or demineralized borated water.	Treated borated water
Treated borated water > 140°F	Treated or demineralized borated water above stress corrosion cracking (SCC) threshold for stainless steel.	Treated borated water > 140°F
Water – flowing	Water that is refreshed; thus, it has a greater impact on leaching and can include rainwater, raw water, groundwater, or water flowing under a foundation.	Water – flowing
Water – standing	Water that is stagnant and unrefreshed, thus possibly resulting in increased ionic strength up to saturation.	Water – standing

Table 3.0-3
Service Environments for Electrical Aging Management Reviews

Environment	Description	Corresponding NUREG-2191 Environments
Air – indoor controlled	This environment is one to which the specified internal or external surface of the component or structure is exposed; a humidity-controlled (i.e., air conditioned) environment. For electrical purposes, control must be sufficient to eliminate the cited aging effects of contamination and oxidation without affecting the resistance.	Air – indoor controlled
Air – indoor uncontrolled	This environment is for indoor locations that are sheltered/ protected from weather. Surfaces of components in this environment may be wetted, but only rarely; equipment surfaces are normally dry.	Air – indoor uncontrolled
Air – outdoor	The outdoor environment consists of atmospheric air, salt-laden air, ambient temperature and humidity, and exposure to precipitation.	Air – outdoor
Air with borated water leakage	This environment is similar to the air-indoor uncontrolled environment, but is used for components located within buildings that have systems containing treated borated water as they may be susceptible to borated water leakage and subsequent boric acid corrosion.	Air with borated water leakage
Heat and air Moisture and air Radiation and air	Condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials caused by heat, radiation, or moisture and air.	Adverse localized environment caused by heat, radiation or moisture
Significant moisture	Condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials caused by significant moisture (moisture that lasts more than a few days—e.g., cable in standing water).	Adverse localized environment caused by significant moisture

3.1 AGING MANAGEMENT OF 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 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 Coolant and Connected Piping (Section 2.3.1.1)
- Pressurizers (Section 2.3.1.2)
- Reactor Vessels (Section 2.3.1.3)
- Reactor Vessel Internals (Section 2.3.1.4)
- Steam Generators (Section 2.3.1.5)

3.1.2 Results

The following tables summarize the results of the aging management review for the Reactor Coolant System.

Table 3.1.2-1, Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation

Table 3.1.2-2, Pressurizers – Summary of Aging Management Evaluation

Table 3.1.2-3, Reactor Vessels – Summary of Aging Management Evaluation

Table 3.1.2-4, Reactor Vessel Internals – Summary of Aging Management Evaluation

Table 3.1.2-5, Steam Generators – 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 Coolant and Connected Piping

Materials

The materials of construction for the Reactor Coolant and Connected Piping components are:

- Carbon steel
- Cast austenitic stainless steel (CASS)
- Coating
- Stainless steel

Environments

The Reactor Coolant and Connected Piping components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Gas
- Reactor coolant
- Treated borated water
- Treated borated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Reactor Coolant and Connected Piping require management:

- Cracking
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction in fracture toughness
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Coolant and Connected Piping components:

- ASME Code Class 1 Small-Bore Piping
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Boric Acid Corrosion
- Bolting Integrity
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks
- One-Time Inspection
- Pressurizer Surge Line Fatigue
- Thermal Aging Embrittlement of CASS
- Water Chemistry

3.1.2.1.2 Pressurizers

Materials

The Materials of construction for the Pressurizers components are:

- Carbon steel
- Nickel alloy
- Stainless steel

Environments

The Pressurizers components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant

Aging Effects Requiring Management

The following aging effects associated with the Pressurizers require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Pressurizers components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Boric Acid Corrosion
- Water Chemistry
- Bolting Integrity
- External Surfaces Monitoring of Mechanical Components

3.1.2.1.3 Reactor Vessels

Materials

The materials of construction for the Reactor Vessels components are:

- Carbon steel with nickel alloy clad
- Carbon steel with stainless steel clad
- High strength steel
- Nickel alloy
- Stainless steel

Environments

The Reactor Vessels components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Neutron flux

Aging Effects Requiring Management

The following aging effects associated with the Reactor Vessels require management:

- Cracking
- Loss of material
- Loss of fracture toughness

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Vessels components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Boric Acid Corrosion
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components
- External Surfaces Monitoring of Mechanical Components
- Flux Thimble Tube Inspection
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Neutron Fluence Monitoring
- Reactor Head Closure Stud Bolting
- Reactor Vessel Material Surveillance
- Water Chemistry

3.1.2.1.4 Reactor Vessel Internals

Materials

The materials of construction for the Reactor Vessel Internals components are:

- CASS
- Nickel alloy
- Stainless steel

Environments

The Reactor Vessel Internals components are exposed to the following environments:

- Reactor coolant
- Neutron flux

Aging Effects Requiring Management

The following aging effects associated with the Reactor Vessel Internals require management:

- Cracking
- Changes in dimensions
- Loss of material
- Loss of fracture toughness
- Wear

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Vessel Internals components:

- Reactor Vessel Internals
- Water Chemistry

3.1.2.1.5 Steam Generators

Materials

The materials of construction for the Steam Generators components are:

- Alloy steel
- Alloy steel with nickel alloy clad
- Carbon steel
- Carbon steel with stainless steel clad
- Low alloy steel
- Nickel alloy
- Nickel alloy with chrome plating
- Stainless steel

Environments

The Steam Generators components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Treated water
- Treated water >140°F
- Steam

Aging Effects Requiring Management

The following aging effects associated with the Steam Generators require management:

- Cracking
- Loss of material
- Reduction of heat transfer
- Wall thinning
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Steam Generators components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- One-Time Inspection
- Steam Generators
- Water Chemistry

3.1.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Reactor Coolant System, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.1.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). These types of TLAAs are addressed separately in Section 4.3, "Metal Fatigue," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage for reactor coolant system components subject to fatigue is addressed in Section 4.3, "Metal Fatigue" of this document. The Metal Fatigue TLAA recognizes that the pressurizer surge line is not sufficiently managed based on the analysis and a plant-specific AMP is required to manage the pressurizer surge line for cumulative fatigue damage. This plant-specific AMP, Pressurizer Surge Line Fatigue, is described in Appendix B.

Additionally, Reactor Vessel Internals components are subject to inspections to monitor for cracking due to fatigue in components which may be susceptible. These inspections are performed in accordance with the Reactor Vessel Internals AMP or the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP for core support components, consistent with NUREG-2191. These AMPs are described in Appendix B.

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).*

   PTN uses a Model 44 Westinghouse steam generator per UFSAR Table 14.3.4.1-1 and the design includes a high-stress region at the shell to transition cone welds. Loss of material due to general, pitting, and crevice corrosion in the lower shell to transition cone weld and transition cone to upper shell weld will be managed by the Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMPs. These two welds (lower shell to transition cone and transition cone to upper shell) are original welds. The enhanced techniques described in IN 90-04 are consistent with the techniques currently used in PTN's Section XI inspection program for the original transition cone welds, and no further augmented inspection is required.

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.

The PTN Units 3 and 4 steam generators (with the exception of the channel heads and steam domes) were replaced in 1982 and 1983, respectively. The steam generator transition cone was cut to replace the bottom portion of the steam generator. The resulting new circumferential weld is a field weld, as opposed to the upper and lower transition cone welds which were performed in a controlled manufacturing facility. The surface conditions of the new circumferential weld may result in flow conditions more conducive to initiation of general, pitting, and crevice corrosion. The new circumferential closure weld will be managed by the Water Chemistry AMP. In addition, a one-time Inspection, in accordance with the One-Time Inspection AMP, of the new circumferential closure weld will be conducted to verify the effectiveness of the Water Chemistry AMP in managing general and pitting corrosion of the shell. This inspection will be a volumetric inspection consistent with the techniques currently in place for the original transition cone welds, and will be performed prior to entering the SPEO.

3.1.2.2.3 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement

1. *Neutron irradiation embrittlement is a TLAA to be evaluated for the subsequent period of extended operation for all ferritic materials that have a neutron fluence greater than 10^{17} n/cm^2 (E >1 MeV) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, "Reactor Pressure Vessel Neutron Embrittlement Analysis," of this SRP-SLR.*

   Loss of fracture toughness due to neutron irradiation embrittlement of the reactor vessel beltline material is an aging effect and mechanism assessed by a time-limited aging analysis (TLAA). The evaluation of neutron irradiation embrittlement as a TLAA is discussed in Section 4.2, "Reactor Vessel Neutron Embrittlement Analysis."

2. *Loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. A reactor vessel material surveillance program monitors neutron irradiation embrittlement of the reactor vessel. The Reactor Vessel Material Surveillance program is either a plant-specific surveillance program or an integrated surveillance program, depending on matters such as the composition of limiting materials and the availability of surveillance capsules.*

   In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further NRC staff evaluation is required for a subsequent license renewal

(SLR). Specific recommendations for an acceptable AMP are provided in GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance."

A Neutron Fluence Monitoring program may be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the plant's reactor vessel neutron irradiation embrittlement TLAAs. These TLAAs are the subjects of the topics discussed in SRP-SLR Section 3.1.2.2.3.1 and "acceptance criteria" and "review procedure" guidance in SRP-SLR Section 4.2. For those applicants that determine it is appropriate to include a Neutron Fluence Monitoring AMP in their SLRAs, the program is to be implemented in conjunction with the applicant's implementation of an AMP that corresponds to GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance." Specific recommendations for an acceptable Neutron Fluence Monitoring AMP are provided in GALL-SLR Report AMP X.M2, "Neutron Fluence Monitoring."

The neutron fluence TLAA in Section 4.2, "Reactor Vessel Neutron Embrittlement Analysis," is managed by the Neutron Fluence Monitoring AMP, which is addressed in Section B.2.2.2. The Neutron Fluence Monitoring AMP is a site-specific program. This AMP is consistent with 10 CFR Appendix H. The capsule withdrawal schedule has previously been approved by the NRC, and remains applicable for the SPEO. The Neutron Fluence Monitoring AMP monitors the plant conditions to ensure the assumptions of the TLAA remain bounding and is implemented in conjunction with the Reactor Vessel Material Surveillance AMP.

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.*

   This item is not applicable to PTN reactor internals. This item is intended to be applicable for a Babcock & Wilcox PWRs only and is not used for PTN, which is a Westinghouse design.

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.

This item is not applicable to Turkey Point. This item is intended to be applicable for a BWR only and is not used for PTN, which is a PWR.

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 NUREG-2192, SRP-SLR).*

   This item is not applicable to Turkey Point. This item is intended to be applicable for a BWR only and is not used for PTN, which is a PWR.

3.1.2.2.5 Crack Growth due to Cyclic Loading

Crack growth due to cyclic loading could occur in reactor pressure vessel (RPV) shell forgings clad with SS using a high-heat-input welding process. Therefore, the current licensing basis (CLB) may include flaw growth evaluations of intergranular separations (i.e., underclad cracks) that have been identified in the RPV-to-cladding welds for the vessel. The evaluations apply to SA-508 Class 2 RPV forging components where the cladding was deposited and welded to the vessel using a high-heat-input welding process. For CLBs that include these types of evaluations, the evaluations may need to be identified as TLAAs if they are determined to conform to the six criteria for defining TLAAs in 10 CFR 54.3(a). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code Section XI2. See SRP-SLR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

Crack growth due to cyclic loading in the RPV shell forgings clad with stainless steel using a high-heat-input welding process is addressed by a TLAA in Section 4.7, "Other Plant-Specific TLAAs," of this application.

3.1.2.2.6 Cracking due to Stress Corrosion Cracking

1. *Cracking due to SCC could occur in PWR SS bottom-mounted instrument guide tubes exposed to reactor coolant. Further evaluation is recommended to ensure that these aging effects are adequately managed. A plant-specific AMP should be evaluated to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

   The effects of cracking due to SCC in the bottom-mounted instrumentation guide tubes are managed using the Water Chemistry AMP and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. The Water Chemistry AMP will minimize the contaminants which promote SCC. VT-2 Inspections are performed as a part of the Section XI AMP and will identify degradation of the stainless steel bottom-mounted instrumentation guide tubes.

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).*

   Section 3.1.2.2.6.2 of the SRP-SLR states that SCC could occur in CASS components that do not meet the NUREG-0313 guidelines regarding ferrite and carbon content. However, review of NUREG-0313 describes industry experience where SCC of CASS components occurred in boiling water reactors (BWRs) primarily due to susceptible CASS components being exposed to BWR water chemistry with high levels of oxygen and other contaminants. NUREG-0313 does not identify SCC of CASS components as being problematic in pressurized water reactors (PWRs) like PTN. This can be attributed to the very tight controls of PWR water chemistry for dissolved oxygen and other aggressive contaminants. The lack of SCC in PTN Class 1 CASS piping and piping components is confirmed in the Operating Experience (OE) Aging Effects Report. Therefore, the Water Chemistry program is effective in managing the aging effects of cracking due to SCC in Class 1 RCS CASS piping and piping components and an additional plant-specific program to manage aging is not required.

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.

The stainless steel reactor vessel flange leak detection lines are exposed to an internal and external environment of air – indoor uncontrolled. A review of PTN operating experience confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program. The reactor vessel flange leak detection line has not experienced SCC, but will be treated as susceptible based on the plant wide operating experience.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed via the External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components program is described in Section B.2.3.23 and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is described in Section B.2.3.25.

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).

This item is not applicable to PTN. This item is intended to be applicable for a BWR only and is not used for PTN, which is a PWR.

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).

This item is not applicable to Turkey Point as a feedwater impingement plate is not a Westinghouse steam generator Model 44 component.

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.

Reactor Vessel Internals AMP is based on the MRP-227-A framework modified by a gap analysis. Appendix C of this application provides a detailed description of this gap analysis.

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).

The effects of loss of material due to wear in the CRDM head penetrations is managed using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. The following enhancements are added to the existing program to adequately monitor the condition of the CRDM nozzles;

- Evaluate industry operating experience related to CRDM housing penetration wear due to thermal sleeve centering pads and initiatives to measure CRDM housing penetration wear and resulting nozzle wall thickness.
- Develop a wear depth measurement process.
- Incorporate inspections using the demonstrated process at accessible locations to measure depth of wear on the CRDM housing penetration wall associated with contact.
- Develop a procedure to estimate the wall thickness of the accessible CRDM housing penetration wear in the area of interest at the end of the next reactor vessel head inspection interval and compare the projected wall thickness to the thickness used in the design basis analyses to demonstrate validity of the analyses.

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.*

   This item is not applicable to Turkey Point as the CRDM thermal sleeves do not perform a subsequent license renewal intended function. The wear interaction which impacts the CRDM head penetration nozzles, which do perform a subsequent license renewal intended function, is described above in Section 3.1.2.2.10, item 1.

3.1.2.2.11 <u>Cracking due to Primary Water Stress Corrosion Cracking</u>

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.

Turkey Point has an Alloy 600 divider plate and the EPRI analysis is applicable. FPL is evaluating the industry analysis (EPRI TR-3002002850) as part of the existing Steam Generators AMP for the current PEO to determine whether it is bounding for Turkey Point. This evaluation is scheduled for completion by the end of 2018.

If the analysis is determined to be bounding, the Steam Generators AMP will be revised to address primary water stress corrosion cracking in the divider plate for the PEO, and carried forward through the SPEO. A plant-specific AMP is no necessary.

If the analysis is determined to not be bounding, a One-Time Inspection AMP will be implemented for SLR to verify the effectiveness of the Water Chemistry and Steam Generators AMPs. The examinations will be performed by qualified personnel and the techniques used will be capable of detection primary water stress corrosion cracking in the divider plate assemblies and associated welds.

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.

Turkey Point has a permanently approved H* alternate repair criteria for both the hot- and cold-leg side of the steam generator per ADAMS accession number ML12292A342. As such, the weld is no longer part of the reactor coolant pressure boundary, and a plant-specific AMP is not necessary.

3.1.2.2.12 Cracking due to Irradiation-Assisted Stress Corrosion Cracking

GALL-SLR Report AMP XI.M9, "BWR Vessel Internals," manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience cracking due to IASCC. The existing Boiling Water Reactor Vessel and Internals Project (BWRVIP) examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. However, increases in neutron fluence during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage cracking due to IASCC. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant identifies the components to be inspected and performs supplemental inspections to adequately manage IASCC. In addition, the applicant should confirm the adequacy of any *necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.*

This item is not applicable to PTN. This item is intended to be applicable for a BWR only and is not used for PTN, which is a PWR.

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.

This item is not applicable to Turkey Point. This item is intended to be applicable for a BWR only and is not used for Turkey Point, which is a PWR.

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.

This item is not applicable to PTN. This item is intended to be applicable for a BWR only and is not used for PTN, which is a PWR.

3.1.2.2.15 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The *rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.*

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

There are no reactor coolant system stainless steel or steel piping or piping components, within the scope of subsequent license renewal, exposed to concrete at Turkey Point. Where reactor coolant system piping is required to penetrate concrete, penetration sleeves are used. This is addressed further in Section 3.5.

3.1.2.2.16 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy *components, rain and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a One-Time Inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping and piping components exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage loss of material due to pitting or crevice corrosion. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, One-Time Inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

Based on a review of Turkey Point operating experience, the environment is sufficiently aggressive to cause loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy components exposed to air. As such, the External Surfaces Monitoring of Mechanical Components AMP will be used to manage these aging effects.

3.1.2.2.17 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix A.2 of the SRP-SLR)

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B.

3.1.2.2.18 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, “Operating Experience for Aging Management Programs” in the SRP-SLR.

The Operating Experience process and acceptance criteria are described in Appendix B.

3.1.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Reactor Coolant System components:

- Section 4.2, Reactor Vessel Neutron Embrittlement Analysis
- Section 4.3, Metal Fatigue
- Section 4.7, Other Plant-Specific TLAAs

3.1.3 Conclusion

The Reactor Coolant System piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Reactor Vessel, Internals, and Reactor Coolant System components are identified in the summaries in Section 3.1.2 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Coolant System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.1-1
Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 001	Steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of steel reactor vessel closure flange assembly components exposed to uncontrolled indoor air. Further evaluation is documented in Section 3.1.2.2.1.
3.1-1, 002	Nickel alloy tubes and sleeves exposed to reactor coolant, secondary feedwater/steam	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of fatigue of nickel alloy tubes and sleeves exposed to reactor coolant, secondary feedwater or steam. Further evaluation is documented in Section 3.1.2.2.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 003	Stainless steel, nickel alloy reactor vessel internal components exposed to reactor coolant, neutron flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of fatigue of reactor vessel internals components exposed to reactor coolant. Further evaluation is documented in Section 3.1.2.2.1.
3.1-1, 004	Steel pressure vessel support skirt and attachment welds	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Not applicable. The PTN reactor vessel is nozzle supported and there is no support skirt.
3.1-1, 005	Steel, stainless steel, steel (with stainless steel or nickel alloy cladding) steam generator components, pressurizer relief tank components, piping components, bolting	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of fatigue of steam generator components as well as reactor coolant pressure boundary bolting, piping and piping components. However, for the pressurizer surge line, cumulative fatigue damage is managed by the PTN-specific Pressurizer Surge Line Fatigue AMP. Further evaluation is documented in Section 3.1.2.2.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 006	This line item only applies to BWRs.				
3.1-1, 007	This line item only applies to BWRs.				
3.1-1, 008	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy steam generator components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of fatigue of steam generator components exposed to reactor coolant. Further evaluation is documented in Section 3.1.2.2.1.
3.1-1, 009	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor coolant pressure boundary piping, piping components; other pressure retaining components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of fatigue of pressurizer components exposed to reactor coolant. Further evaluation is documented in Section 3.1.2.2.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 010	Steel (with or without nickel alloy or stainless steel cladding), stainless steel, or nickel alloy reactor vessel components: nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of fatigue of reactor vessel components exposed to reactor coolant. Further evaluation is documented in Section 3.1.2.2.1.
3.1-1, 011	Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Fatigue of metal components is addressed as a TLAA in Section 4.3, which is credited for the management of fatigue of steel pump and valve closure bolting. Further evaluation is documented in Section 3.1.2.2.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 012	Steel steam generator components: upper and lower shells, transition cone; new transition cone closure weld exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Sections 3.1.2.2.2.1 and 3.1.2.2.2.2)	Loss of material due to general, pitting, and crevice corrosion will be managed using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs for the original transition cone welds. The new circumferential weld will be managed using the Water Chemistry and One-Time Inspection AMPs. Further evaluation is documented in Section 3.1.2.2.2.
3.1-1, 013	Steel (with or without stainless steel or nickel alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, SRP-SLR Section 4.2 "Reactor Pressure Vessel Neutron Embrittlement"	Yes (SRP-SLR Section 3.1.2.2.3.1)	Consistent with NUREG-2191. The Reactor Vessel Irradiation Embrittlement is addressed as a TLAA in Section 4.2, which is credited for managing loss of fracture toughness in high neutron flux regions of the steel reactor vessel. Further evaluation is documented in Section 3.1.2.2.3, Item 1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 014	Steel (with or without cladding) reactor vessel beltline shell, nozzle, and weld components; exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	AMP XI.M31, "Reactor Vessel Material Surveillance," and AMP X.M2, "Neutron Fluence Monitoring"	Yes (SRP-SLR Section 3.1.2.2.3.2)	Consistent with NUREG-2191. Loss of fracture toughness of the steel reactor vessel beltline shell, nozzle and welds in the beltline region will be managed with the Reactor Vessel Material Surveillance and Neutron Fluence Monitoring AMPs. Further evaluation is documented in Section 3.1.2.2.3, Item 2.
3.1-1, 015	This line item only applies to B&W designs.				
3.1-1, 016	This line item only applies to BWRs.				
3.1-1, 017	This line item only applies to BWRs.				
3.1-1, 018	Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat- input welding process exposed to reactor coolant	Crack growth due to cyclic loading	TLAA, SRP-SLR Section 4.7 "Other Plant-Specific TLAAs"	Yes (SRP-SLR Section 3.1.2.2.5)	Consistent with NUREG-2191. The reactor vessel underclad cracking is addressed as a TLAA in Section 4.7, which is credited for managing crack growth in reactor vessel shell components. Further evaluation is documented in Section 3.1.2.2.5.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 019	Stainless steel reactor vessel bottom-mounted instrument guide tubes (external to reactor vessel) exposed to reactor coolant	Cracking due to SCC	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.6.1)	The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs will be used to manage SCC in the stainless steel reactor vessel bottom-mounted instrument guide tubes exposed to reactor coolant. Further evaluation is documented in Section 3.1.2.2.6.
3.1-1, 020	CASS Class 1 piping, piping components exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, "Water Chemistry" and plant specific aging management program	Yes (SRP-SLR Section 3.1.2.2.6.2)	The Water Chemistry AMP will be used to manage SCC in Class 1 CASS piping. A plant-specific AMP is not necessary for further management. Further evaluation is documented in Section 3.1.2.2.6, Item 2.
3.1-1, 021	This line item only applies to BWRs.				
3.1-1, 022	Steel steam generator feedwater impingement plate and support exposed to secondary feedwater	Loss of material due to erosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.8)	Not applicable. This component does not exist at PTN. Further evaluation is documented in Section 3.1.2.2.8.
3.1-1, 023	There is no 3.1-1, 023 in NUREG-2192.				
3.1-1, 024	There is no 3.1-1, 024 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 025	Steel (with nickel alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M19, "Steam Generators." In addition, a plant-specific program is to be evaluated.	Yes (SRP-SLR Sections 3.1.2.2.11.1 and 3.1.2.2.11.2)	The Water Chemistry and Steam Generators AMPs will be used to manage primary water SCC in the divider plate exposed to reactor coolant. A potential enhancement to the Steam Generators AMP is identified to address EPRI Report 3002002850 regarding SCC in the divider plate. Further evaluation is documented in Section 3.1.2.2.11.
3.1-1, 026	There is no 3.1-1, 026 in NUREG-2192.				
3.1-1, 027	There is no 3.1-1, 027 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 028	"Existing Programs" components: Stainless steel, nickel alloy Westinghouse control rod guide tube support pins, and Combustion Engineering thermal shield positioning pins; Zircaloy-4 Combustion Engineering incore instrumentation thimble tubes exposed to reactor coolant and neutron flux	Loss of material due to wear; cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with the recommendations of MRP-227-A, as modified by the gap analysis in Appendix C, the Reactor Vessel Internals AMP is used to manage loss of material due to wear, cracking due SCC, cracking due to irradiation-assisted SCC, and fatigue in reactor vessel internals components grouped as "Existing Programs." However, because each component is not subject to every aging mechanism listed, the applicable aging mechanisms for these components are identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 029	This line item only applies to BWRs.				
3.1-1, 030	This line item only applies to BWRs.				
3.1-1, 031	This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 032	Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure (not already referenced as ASME Section XI Examination Category B- N-3 core support structure components in MRP-227- A), exposed to reactor coolant and neutron flux	Cracking, loss of material due to wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage cracking and loss of material due to wear in reactor vessel internals core support structures exposed to reactor coolant and neutron flux. However, because each component is not subject to every aging effect listed, the applicable aging effects for these components are identified in Appendix C.
3.1-1, 033	Stainless steel, steel with stainless steel cladding Class 1 reactor coolant pressure boundary components exposed to reactor coolant	Cracking due to SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs will be used to manage SCC in Class 1 RCPB components exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 034	Stainless steel, steel with stainless steel cladding pressurizer relief tank (tank shell and heads, flanges, nozzles) exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Not applicable. The pressurizer relief tank is not a part of the RCS pressure boundary and is not stainless steel clad. The pressurizer relief tank will not be managed as an ASME Section XI component. The pressurizer relief tank requires aging management for a structural integrity intended function and is managed as component type “Tank” in Table 3.1.2-1.
3.1-1, 035	Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage cracking due to cyclic loading in stainless steel, steel with stainless steel cladding, reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant. This line item is also used for stainless steel heat exchangers exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 036	Steel, stainless steel pressurizer integral support exposed to any environment	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage cracking due to cyclic loading in the pressurizer support skirt.
3.1-1, 037	Steel reactor vessel flange	Loss of material due to wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage loss of material due to wear of the reactor vessel flange.
3.1-1, 038	CASS Class 1 valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage loss of fracture toughness in CASS Class 1 valve bodies and bonnets exposed to reactor coolant > 250 °C.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 039	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant	Cracking due to SCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), IGSCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), or thermal, mechanical, or vibratory loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," AMP XI.M2, "Water Chemistry," and XI.M35, "ASME Code Class 1 Small-Bore Piping"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry and ASME Code Class 1 Small-Bore Piping AMPs will be used to manage SCC in stainless steel piping < 4" exposed to reactor coolant.
3.1-1, 040	Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage cracking due to cyclic loading in stainless steel, or steel with stainless steel cladding pressurizer components exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 040a	Nickel alloy core support pads; core guide lugs exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs will be used to manage SCC in the nickel alloy core support lugs exposed to reactor coolant.
3.1-1, 041	This line item only applies to BWRs.				
3.1-1, 042	Steel with stainless steel or nickel alloy cladding; stainless steel primary side components; steam generator upper and lower heads, and tube sheet welds; pressurizer components exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs will be used to manage SCC and PWSCC in stainless steel or steel with stainless steel cladding pressurizer components exposed to reactor coolant.
3.1-1, 043	This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 044	Steel steam generator secondary manway and handhole cover seating surfaces exposed to treated water, steam	Loss of material due to erosion	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage loss of material due to erosion of the steel steam generator secondary manway and handhole cover seating surfaces exposed to treated water, steam.
3.1-1, 045	Nickel alloy, steel with nickel alloy cladding reactor coolant pressure boundary components exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," and AMP XI.M2, "Water Chemistry," and, for nickel-alloy, AMP XI.M11B, "Cracking of Nickel- Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in RCPB Components (PWRs Only)"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, Water Chemistry, and Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMPs will be used to manage PWSCC in nickel alloy reactor coolant pressure boundary components exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 046	Stainless steel, nickel alloy control rod drive head penetration pressure housings, reactor vessel nozzles, nozzle safe ends and welds exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," and AMP XI.M2, "Water Chemistry," and, for nickel-alloy, AMP XI.M11B, "Cracking of Nickel- Alloy Components and Loss of Material Due to Boric Acid-induced corrosion in RCPB Components (PWRs Only)"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs will be used to manage SCC and PWSCC in stainless steel and steel with stainless steel cladding reactor coolant pressure boundary components exposed to reactor coolant.
3.1-1, 047	Stainless steel, nickel alloy control rod drive head penetration pressure housing exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs will be used to manage SCC and PWSCC in stainless steel CRDM head penetration pressure housings and penetrations nozzles exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 048	Steel external surfaces: reactor vessel top head, reactor vessel bottom head, reactor coolant pressure boundary piping or components adjacent to dissimilar metal (Alloy 82/182) welds exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion," and AMP XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid- Induced Corrosion in RCPB Components (PWRs Only)"	No	Not used. All instances of nickel alloy welds in contact with steel external surfaces are addressed with item 3.1-1, 045. Additionally, loss of material due to boric acid corrosion is recognized for all steel external surfaces within proximity to borated water.
3.1-1, 049	Steel reactor vessel, piping, piping components in the reactor coolant pressure boundary of PWRs, and applicable exterior attachments, or steel steam generators in PWRs: external surfaces or closure bolting exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion AMP will be used to manage loss of material due to boric acid corrosion in steel external surfaces of Class 1 components within proximity to borated water.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 050	CASS Class 1 piping, piping components (including pump casings and control rod drive pressure housings) exposed to reactor coolant >250 °F (>482 °C)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Consistent with NUREG-2191. The Thermal Aging Embrittlement of CASS AMP will be used to manage loss of fracture toughness in Class 1 CASS piping and pump casings exposed to reactor coolant > 250 °C (> 482 °F).
3.1-1, 051a	This line item only applies to Babcock & Wilcox designs.				
3.1-1, 051b	This line item only applies to Babcock & Wilcox designs.				
3.1-1, 052a	This line item only applies to Combustion Engineering designs.				
3.1-1, 052b	This line item only applies to Combustion Engineering designs.				
3.1-1, 052c	This line item only applies to Combustion Engineering designs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 053a	Stainless steel, nickel alloy Westinghouse reactor internal "Primary" components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals and Water Chemistry AMPs will be used to manage cracking due to SCC, irradiation assisted SCC and fatigue in reactor vessel internals “Primary” components exposed to reactor coolant and neutron flux. However, multiple components are not susceptible to every aging effect listed, resulting in a note “I” in Table 3.1.2-4. The applicable aging effects for these components are identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 053b	Stainless steel Westinghouse reactor internal "Expansion" components exposed to reactor coolant and neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals and Water Chemistry AMPs will be used to manage cracking due to SCC, irradiation assisted SCC and fatigue in reactor vessel internals “Expansion” components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.9.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 053c	Stainless steel, nickel alloy Westinghouse reactor internal "Existing Programs" components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals and Water Chemistry AMPs will be used to manage cracking due to SCC, irradiation assisted SCC and fatigue in reactor vessel internals “Existing Programs” components exposed to reactor coolant and neutron flux. However, multiple components are not susceptible to every aging effect listed, resulting in a note “I” in Table 3.1.2-4. The applicable aging effects for these components are identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 054	Stainless steel bottom-mounted instrument system flux thimble tubes (with or without chrome plating) exposed to reactor coolant and neutron flux	Loss of material due to wear	AMP XI.M37, "Flux Thimble Tube Inspection"	No	Consistent with NUREG-2191. The Flux Thimble Tube Inspection AMP will be used to manage loss of material in stainless steel bottom-mounted instrument system flux thimble tubes exposed to reactor coolant and neutron flux.
3.1-1, 055a	This line item only applies to Babcock and Wilcox designs.				
3.1-1, 055b	This line item only applies to Combustion Engineering designs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 055c	Stainless steel, nickel alloy Westinghouse reactor internal "No Additional Measures" components exposed to reactor coolant, neutron flux	No additional aging management for reactor internal "No Additional Measures" components unless required by ASME Section XI, Examination Category B-N-3 or relevant operating experience exists	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals AMP will be used to manage reactor vessel internals “No Additional Measures” components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 056a	This line item only applies to Combustion Engineering designs.				
3.1-1, 056b	This line item only applies to Combustion Engineering designs.				
3.1-1, 056c	This line item only applies to Combustion Engineering designs.				
3.1-1, 057	There is no 3.1-1, 057 in NUREG-2192.				
3.1-1, 058a	This line item only applies to Babcock and Wilcox designs.				
3.1-1, 058b	This line item only applies to Babcock and Wilcox designs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 059a	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor internal "Primary" components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals AMP will be used to manage reactor vessel internals "Primary" components exposed to reactor coolant and neutron flux. However, the internals hold down springs are not susceptible to every aging effect listed, resulting in a note "I" in Table 3.1.2-4. The applicable aging effects for the internals hold down springs are identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 059b	Stainless steel (SS, including CASS, PH SS or martensitic SS) Westinghouse reactor internal "Expansion" components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	The Reactor Vessel Internals AMP will be used to manage reactor vessel internals “Expansion” components exposed to reactor coolant and neutron flux. However, the core barrel outlet nozzle welds and the lower support forging are not susceptible to the aging mechanisms identified resulting in a note “I” in Table 3.1.2-4. The applicable aging effects for the core barrel outlet nozzle welds and the lower support forging are identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 059c	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor internal "Existing Programs" components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	The Reactor Vessel Internals AMP will be used to manage reactor vessel internals “Expansion” components exposed to reactor coolant and neutron flux. However, the clevis insert bolting is not susceptible to thermal and irradiation-enhanced stress relaxation or creep resulting in a note “I” in Table 3.1.2-4. The applicable aging effects for the clevis insert bolting are identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 060	This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 061	Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam	Wall thinning due to flow- accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion AMP will be used to manage wall thinning in the steam generator feedwater nozzle, steam outlet nozzle, and blowdown piping exposed to secondary feedwater/steam.
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	While the control rod drive head penetration flange is not applicable to Turkey Point, the Bolting Integrity AMP will be used to manage SCC in RCPB stainless steel bolting exposed to air-indoor uncontrolled.
3.1-1, 063	This line item only applies to BWRs.				
3.1-1, 064	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage loss of material in steel and stainless steel closure bolting exposed to air-indoor uncontrolled.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 065	Stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Loss of material due to wear	AMP XI.M18, "Bolting Integrity"	No	Not applicable. The control rod drive head penetration flange is not attached using bolting exposed to air-indoor uncontrolled.
3.1-1, 066	Steel, stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage loss of preload in the pressurizer manway cover bolts and RCS piping and piping components bolting exposed to air-indoor uncontrolled.
3.1-1, 067	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage loss of preload in the steam generator primary manway and secondary closure bolting exposed to air-indoor uncontrolled (external).
3.1-1, 068	Nickel alloy steam generator tubes exposed to secondary feedwater or steam	Changes in dimension ("denting") due to corrosion of carbon steel tube support plate	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Not applicable. The Turkey Point tube support plates are not carbon steel.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 069	Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam	Cracking due to outer diameter SCC, intergranular attack	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Steam Generators and Water Chemistry AMPs will be used to manage cracking in nickel alloy U-tubes.
3.1-1, 070	Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Steam Generators and Water Chemistry AMPs will be used to manage cracking in nickel alloy U-tubes and tube plugs exposed to reactor coolant.
3.1-1, 071	Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti- vibration bars exposed to secondary feedwater or steam	Cracking due to SCC or other mechanism(s); loss of material due general (steel only), pitting, crevice corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 The Steam Generators and Water Chemistry AMPs will be used to manage cracking in nickel alloy and stainless steel steam generator components exposed to treated feedwater and steam.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 072	Steel steam generator tube support plate, tube bundle wrapper, supports and mounting hardware exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion, erosion, ligament cracking due to corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry" (corrosion based aging effects and mechanisms only)	No	Consistent with NUREG-2191 The Steam Generators and Water Chemistry AMPs will be used to manage loss of material in the steam generator tube bundle wrapper exposed to secondary feedwater or steam.
3.1-1, 073	Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam	Loss of material due to wastage, pitting corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 The Steam Generators and Water Chemistry AMPs will be used to manage loss of materials in the U-tubes exposed to phosphate chemistry in secondary feedwater or steam.
3.1-1, 074	Steel steam generator upper assembly and separators including feedwater inlet ring and support exposed to secondary feedwater or steam	Wall thinning due to flow- accelerated corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Steam Generators and Water Chemistry AMPs will be used to manage wall thinning in the feedwater ring and moisture separators exposed to secondary feedwater or steam.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 075	Steel steam generator tube support lattice bars exposed to secondary feedwater or steam	Wall thinning due to flow- accelerated corrosion, general corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Not applicable. Tube support lattice bars are not a Turkey Point steam generator component.
3.1-1, 076	Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti- vibration bars exposed to secondary feedwater or steam	Loss of material due to wear, fretting	AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Steam Generators AMP will be used to manage loss of material of the steam generator anti-vibration bars exposed to secondary feedwater or steam.
3.1-1, 077	Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam	Loss of material due to wear, fretting	AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Steam Generators AMP will be used to manage loss of material due to fretting and wear of the U-tubes exposed to secondary feedwater or steam.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 078	Nickel alloy steam generator components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater or steam	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."	No	Not used. All nickel alloy components on the secondary side of the steam generator are addressed using more specific line items.
3.1-1, 079	This line item only applies to BWRs.				
3.1-1, 080	Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (none-ASME Section XI components) exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. The pressurizer relief tank does not have an internal material of stainless steel. The pressurizer relief tank requires aging management for a structural integrity intended function and managed as component type “Tank” in Table 3.1.2-1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 081	Stainless steel pressurizer spray head exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. Consistent with original license renewal application, the pressurizer spray head is not within the scope of subsequent license renewal at Turkey Point.
3.1-1, 082	Nickel alloy pressurizer spray head exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. Consistent with original license renewal application, the pressurizer spray head is not within the scope of subsequent license renewal at Turkey Point.
3.1-1, 083	Steel steam generator shell assembly exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry and One-Time Inspection AMPs will be used to manage loss of material in the steam generator shell assembly exposed to secondary feedwater or steam.
3.1-1, 084	This line item only applies to BWRs.				
3.1-1, 085	This line item only applies to BWRs.				
3.1-1, 086	Stainless steel steam generator primary side divider plate exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, "Water Chemistry"	No	Not applicable. The steam generator primary side divider plate at Turkey Point is nickel alloy.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 087	Stainless steel, nickel alloy PWR reactor internal components exposed to reactor coolant, neutron flux	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Water Chemistry AMP will be used to manage loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant and neutron flux.
3.1-1, 088	Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Water Chemistry AMP will be used to manage loss of material in stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding reactor coolant pressure boundary components exposed to reactor coolant.
3.1-1, 089	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP will be used to manage loss of material due to pitting, crevice corrosion, and MIC in reactor coolant system steel heat exchanger shells exposed to closed-cycle cooling water.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 090	Copper alloy piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper Class 1 piping or piping components at Turkey Point.
3.1-1, 091	This line item only applies to BWRs.				
3.1-1, 092	Steel (including high-strength steel) reactor vessel closure flange assembly components (including flanges, nut, studs, and washers) exposed to air-indoor uncontrolled	Cracking due to SCC, IGSCC; loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M3, "Reactor Head Closure Stud Bolting"	No	Consistent with NUREG-2191. The Reactor Head Closure Stud Bolting AMP will be used to manage stress corrosion cracking, intergranular stress corrosion cracking, loss of material due to general, pitting, crevice corrosion, and wear of the reactor head closure studs exposed to air-indoor uncontrolled.
3.1-1, 093	Copper alloy >15% Zn or >8% Al piping, piping components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no copper or aluminum piping or piping components in the Turkey Point reactor vessel, internals, or reactor coolant system.
3.1-1, 094	This line item only applies to BWRs.				
3.1-1, 095	This line item only applies to BWRs.				
3.1-1, 096	This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 097	This line item only applies to BWRs.				
3.1-1, 098	This line item only applies to BWRs.				
3.1-1, 099	This line item only applies to BWRs.				
3.1-1, 100	This line item only applies to BWRs.				
3.1-1, 101	This line item only applies to BWRs.				
3.1-1, 102	This line item only applies to BWRs.				
3.1-1, 103	This line item only applies to BWRs.				
3.1-1, 104	This line item only applies to BWRs.				
3.1-1, 105	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no Class 1 piping or piping components exposed to concrete. Further evaluation is documented in Section 3.1.2.2.15.
3.1-1, 106	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not used. The environment and material combination do exist. However, this SLRA does not list combinations in the Table 2s that have no aging effects unless there is only one environment applicable to that component type and material.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 107	Stainless steel piping, piping components exposed to gas, air with borated water leakage	None	None	No	This line item is used to recognize the lack of aging effects in stainless steel piping and piping components with an inside environment of gas. Consistent with item number 3.1-1, 107, this line item is not used to recognize the lack of aging effects in stainless steel piping and piping components exposed to air with borated water leakage.
3.1-1, 108	There is no 3.1-1, 108 in NUREG-2192.				
3.1-1, 109	There is no 3.1-1, 109 in NUREG-2192.				
3.1-1, 110	This line item only applies to BWRs.				
3.1-1, 111	Nickel alloy steam generator tubes exposed to secondary feedwater or steam	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Water Chemistry and Steam Generators AMPs will be used to manage reduction of heat transfer in the steam generator U-tubes exposed to secondary feedwater or steam.
3.1-1, 112	There is no 3.1-1, 112 in NUREG-2192.				
3.1-1, 113	This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 114	Reactor coolant system components defined as ASME Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components or core support structure components, or ASME Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes)	Cracking due to SCC, IGSCC (stainless steel, nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (water chemistry- related or corrosion- related aging effect mechanisms only)	No	Not used. All relevant aging mechanisms requiring management by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD or Water Chemistry are recognized using line items more specific to the individual component type.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 115	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no Class 1 piping or piping components exposed to concrete.
3.1-1, 116	Nickel alloy control rod drive penetration nozzles exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.1)	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP will be used to manage loss of material due to wear in the control rod drive mechanism head penetration housings exposed to reactor coolant. Further evaluation is documented in Section 3.1.2.2.10.
3.1-1, 117	Stainless steel, nickel alloy control rod drive penetration nozzle thermal sleeves exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.2)	Not applicable. The Turkey Point CRDM thermal sleeves do not perform a subsequent license renewal intended function.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 118	Stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, cyclic loading, fatigue	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.9)	The Reactor Vessel Internals AMP will be used to manage cyclic loading and fatigue in stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux. The Water Chemistry AMP will be used to manage cracking due to SCC and irradiation-assisted SCC in stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux. However, multiple components are not susceptible to every aging effect listed, resulting in a note "I" in Table 3.1.2-4. The applicable aging effects for these components are identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 119	Stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement or thermal aging embrittlement; changes in dimensions due to void swelling or distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation or creep; loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.9)	The Reactor Vessel Internals AMP will be used to manage cyclic loading and fatigue in stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux. However, multiple components are not susceptible to every aging effect listed, resulting in a note “I” in Table 3.1.2-4. The applicable aging effects for these components Rare identified in Appendix C. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 120	This line item only applies to BWRs.				
3.1-1, 121	This line item only applies to BWRs.				
3.1-1, 122	There is no 3.1-1, 122 in NUREG-2192.				
3.1-1, 123	There is no 3.1-1, 123 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 Program (AMP)/TLAA	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 AMP will be used to manage loss of material in steel piping and piping components exposed to air.
3.1-1, 125	Nickel alloy steam generator tubes at support plate locations exposed to secondary feedwater or steam	Cracking due to flow- induced vibration, high-cycle fatigue	AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Steam Generators AMP will be used to manage cracking in U-tubes exposed to secondary feedwater or steam.
3.1-1, 126	There is no 3.1-1, 126 in NUREG-2192.				
3.1-1, 127	Steel (with stainless steel or nickel alloy cladding) steam generator heads and tubesheets exposed to reactor coolant	Loss of material due to boric acid corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Water Chemistry and Steam Generators AMPs will be used to manage loss of material in the channel head nozzles and tubesheet of the steam generator exposed to reactor coolant.
3.1-1, 128	This line item only applies to BWRs.				
3.1-1, 129	This line item only applies to BWRs.				
3.1-1, 130	There is no 3.1-1, 130 in NUREG-2192.				
3.1-1, 131	There is no 3.1-1, 131 in NUREG-2192.				
3.1-1, 132	There is no 3.1-1, 132 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 Program (AMP)/TLAA	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	Not applicable. Corrosion inhibitors are added to the reactor coolant system, so long-term loss of material is not an applicable aging effect.
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. No non-metallic thermal insulation associated with reactor coolant piping and piping components performs a SLR intended function.
3.1-1, 135	There is no 3.1-1, 135 in NUREG-2192.				
3.1-1, 136	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.1.2.2.16)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage loss of material in steel piping and piping components exposed to air. Further evaluation is documented in Section 3.1.2.2.16.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 137	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Not applicable. There are no copper alloy piping or piping components in the reactor coolant system.
3.1-1, 138	There is no 3.1-1, 138 in NUREG-2192.				
3.1-1, 139	Stainless steel, nickel alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled, reactor coolant leakage	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes (SRP-SLR Section 3.1.2.2.6.3)	The External Surfaces Monitoring of Mechanical Components AMP is used to manage SCC in the reactor vessel top head leak detection line. Further evaluation is documented in Section 3.1.2.2.6, Item 3.

Table 3.1.2-1
Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	IV.C2.RP-166	3.1-1, 064	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	IV.C2.R-12	3.1-1, 066	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.C2.RP-167	3.1-1, 049	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	IV.C2.R-11	3.1-1, 062	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	IV.C2.RP-166	3.1-1, 064	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	IV.C2.R-12	3.1-1, 066	A
Bolting; piping and piping components	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.C2.R-18	3.1-1, 005	A
Bolting; piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.C2.R-18	3.1-1, 005	A
Bolting; pump and valve	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.C2.RP-44	3.1-1, 011	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting; pump and valve	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.C2.RP-44	3.1-1, 011	A
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water > 140°F (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	VII.E1.AP-119	3.3-1, 008	A
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water > 140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.AP-118	3.3-1, 020	A
Heat exchanger (coil)	Heat transfer	Stainless steel	Reactor coolant	Reduction of heat transfer	Water Chemistry One-Time Inspection	VII.E1.A-101	3.3-1, 017	A
Heat exchanger (coil)	Heat transfer	Stainless steel	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.C2.AP-188	3.3-1, 050	B
Heat exchanger (coil)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C
Heat exchanger (coil)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	C

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (coil)	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	C
Heat exchanger (coil)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	IV.C2.RP-221	3.1-1, 089	D
Heat exchanger (shell)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Heat exchanger (shell)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C
Heat exchanger (shell)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	C
Heat exchanger (shell)	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Heat exchanger (tubes)	Heat transfer	Stainless steel	Reactor coolant	Reduction of heat transfer	Water Chemistry One-Time Inspection	VII.E1.A-101	3.3-1, 017	A
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	VII.E1.A-101	3.3-1, 017	A
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems	VII.C2.AP-188	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water > 140°F (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	VII.E1.AP-119	3.3-1, 008	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water > 140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.AP-118	3.3-1, 020	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	C
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	C
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water > 140°F (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	VII.E1.AP-119	3.3-1, 008	A
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water > 140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.AP-118	3.3-1, 020	A
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Orifice	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	A
Orifice	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	A
Orifice	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Orifice	Throttle	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	A
Orifice	Throttle	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Piping	Pressure boundary	CASS	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	A
Piping	Pressure boundary	CASS	Reactor coolant	Cracking	Water Chemistry	IV.C2.R-05	3.1-1, 020	E
Piping	Pressure boundary	CASS	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Piping	Pressure boundary	CASS	Reactor coolant	Reduction in fracture toughness	Thermal Aging Embrittlement of CASS	IV.C2.R-52	3.1-1, 050	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Piping	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	A
Piping	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Piping < 4" NPS	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry ASME Code Class 1 Small-Bore Piping	IV.C2.RP-235	3.1-1, 039	A
Piping ≥ 4" NPS	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	A
Piping and piping components	Pressure boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.C2.R-18	3.1-1, 005	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural Integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural Integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Piping and piping components	Structural Integrity (attached)	Stainless steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Piping and piping components	Structural Integrity (attached)	Stainless steel	Gas	None	None	IV.E.RP-07	3.1-1, 107	A
Piping and piping components	Structural Integrity	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural Integrity	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Piping and piping components	Structural Integrity	Stainless steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural Integrity	Stainless steel	Gas	None	None	IV.E.RP-07	3.1-1, 107	A
Piping (pressurizer surge line)	Pressure boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage Cracking	Pressurizer Surge Line Fatigue	IV.C2.R-18	3.1-1, 005	E
Pressurizer relief tank	Structural integrity	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Pressurizer relief tank	Structural integrity	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.C2.R-17	3.1-1, 049	A
Pressurizer relief tank	Structural integrity	Carbon steel	Reactor Coolant	Long-term loss of material	One-Time Inspection	V.D1.E-434	3.2-1, 090	A
Pressurizer relief tank	Structural integrity	Carbon steel	Gas	None	None	V.F.EP-7	3.2-1, 064	A
Pressurizer relief tank	Structural integrity	Coating	Reactor Coolant	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	V.D1.E-401	3.2-1, 072	A
Pressurizer relief tank	Structural integrity	Coating	Gas	None	None	-	-	G, 1

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer relief tank (support saddle)	Structural integrity	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Pressurizer relief tank (support saddle)	Structural integrity	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B1.1.T-25	3.5-1, 089	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Pump casing	Pressure boundary	CASS	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	A
Pump casing	Pressure boundary	CASS	Reactor coolant	Cracking	Water Chemistry	IV.C2.R-05	3.1-1, 020	E
Pump casing	Pressure boundary	CASS	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	CASS	Reactor coolant	Reduction in fracture toughness	Thermal Aging Embrittlement of CASS	IV.C2.R-52	3.1-1, 050	A
Thermowell	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C
Thermowell	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	A
Thermowell	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	A
Tubing	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.RP-344	3.1-1, 033	A
Tubing	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Valve body	Pressure boundary	CASS	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C
Valve body	Pressure boundary	CASS	Reactor coolant	Cracking	Water Chemistry	IV.C2.R-05	3.1-1, 020	E

Table 3.1.2-1: Reactor Coolant and Connected Piping — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Valve body	Pressure boundary	CASS	Reactor coolant	Reduction in fracture toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-08	3.1-1, 038	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Valve body	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-56	3.1-1, 035	C
Valve body	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-09	3.1-1, 033	A
Valve body	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A

Notes for Table 3.1.2-1

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

G. Environment not in NUREG-2191 for this component and material.

Plant-Specific Notes for Table 3.1.2-1

1. NUREG-2191 does not identify the material and environment combination of a coating and gas. This combination is present in the pressurizer relief tank, as the tank is coated on the interior and has nitrogen cover gas. However, the only material for which gas has a stated aging effect is elastomers. The aging of elastomers is not related to the gas environment. Therefore, the aging effect of "none" is chosen consistent with other material interactions with nitrogen gas. Additionally, the coating is recognized as requiring management through NUREG-2191 line item V.D1.E-401, as it is also exposed to a reactor coolant environment.

Table 3.1.2-2
Pressurizers — Summary of Aging Management Evaluation

Table 3.1.2-2: Pressurizers — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heater well components	Pressure boundary	Stainless Steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Heater well components	Pressure boundary	Stainless Steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Heater well components	Pressure boundary	Stainless Steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-58	3.1-1, 040	A
Heater well components	Pressure boundary	Stainless Steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-217	3.1-1, 033	A
Heater well components	Pressure boundary	Stainless Steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-25	3.1-1, 042	A

Table 3.1.2-2: Pressurizers — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heater well components	Pressure boundary	Stainless Steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Manway cover bolts	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	IV.C2.RP-166	3.1-1, 064	A
Manway cover bolts	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	IV.C2.R-12	3.1-1, 066	A
Manway cover bolts	Pressure boundary	Low-alloy steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.C2.RP-167	3.1-1, 049	A
Pressurizer components subject to fatigue	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.C2.R-223	3.1-1, 009	A
Pressurizer components subject to fatigue	Pressure boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.C2.R-223	3.1-1, 009	A
Pressurizer components; heads, shell, nozzles, manway cover	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C

Table 3.1.2-2: Pressurizers — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer components; heads, shell, nozzles, manway cover	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.C2.R-17	3.1-1, 049	A
Pressurizer components; manway cover	Pressure boundary	Carbon steel with nickel alloy diaphragm	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-25	3.1-1, 042	A
Pressurizer components; manway cover	Pressure boundary	Carbon steel with nickel alloy diaphragm	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Pressurizer components; heads, shell, nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-58	3.1-1, 040	A
Pressurizer components; heads, shell, nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-25	3.1-1, 042	A

Table 3.1.2-2: Pressurizers — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer components; heads, shell, nozzles,	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Pressurizer components; manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-58	3.1-1, 040	A
Pressurizer components; manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-25	3.1-1, 042	A
Pressurizer components; manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Safe ends, instrument nozzle, thermowells	Pressure boundary	Stainless Steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
Safe ends, instrument nozzle, thermowells	Pressure boundary	Stainless Steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C

Table 3.1.2-2: Pressurizers — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Safe ends, instrument nozzle, thermowells	Pressure boundary	Stainless Steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-58	3.1-1, 040	A
Safe ends, instrument nozzle, thermowells	Pressure boundary	Stainless Steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-25	3.1-1, 042	A
Safe ends, instrument nozzle, thermowells	Pressure boundary	Stainless Steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Support skirt and flange	Structural Support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Support skirt and flange	Structural Support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.C2.R-17	3.1-1, 049	C
Support skirt and flange	Structural Support	Carbon steel	Air – indoor uncontrolled (ext)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-19	3.1-1, 036	A

Table 3.1.2-2: Pressurizers — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Thermal sleeves	Insulate (thermal)	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.C2.R-58	3.1-1, 040	A
Thermal sleeves	Insulate (thermal)	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.C2.R-25	3.1-1, 042	A
Thermal sleeves	Insulate (thermal)	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A

Notes for Table 3.1.2-2

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.1.2-3
Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bottom-mounted instrumentation: flux thimble tubes	Pressure boundary Structural support	Stainless steel	Reactor coolant	Loss of material	Flux Thimble Tube Inspection	IV.B2.RP-284	3.1-1, 054	A
Bottom-mounted instrumentation: guide tubes	Pressure boundary Structural support	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-154	3.1-1, 019	E
Bottom-mounted instrumentation: flux thimble tubes, instrumentation tube safe ends, seal table fittings	Pressure boundary Structural support	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-234	3.1-1, 046	C
Bottom-mounted instrumentation: flux thimble tubes, instrumentation tube safe ends, seal table fittings	Pressure boundary Structural support	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bottom-mounted instrumentation: guide tubes, instrumentation tube safe ends, seal table fittings	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
Bottom-mounted instrumentation: guide tubes, instrumentation tube safe ends, seal table fittings	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Bottom-mounted instrumentation: instrumentation tubes	Pressure boundary Structural support	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
Bottom-mounted instrumentation: instrumentation tubes	Pressure boundary Structural support	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bottom-mounted instrumentation: instrumentation tubes	Pressure boundary Structural support	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	IV.A2.RP-59	3.1-1, 045	A
Bottom-mounted instrumentation: seal table	Structural Support	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
Bottom-mounted instrumentation: seal table	Structural Support	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Core support lugs	Structural Support	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-57	3.1-1, 040a	C

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Core support lugs	Structural Support	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	C
CRDM head penetration nozzles: adapters	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
CRDM head penetration nozzles: adapters	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
CRDM head penetration nozzles: adapters	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-55	3.1-1, 047	A
CRDM head penetration nozzles: adapters	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A
CRDM head penetration nozzles: housings	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
CRDM head penetration nozzles: housings	Pressure boundary	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	IV.A2.RP-186	3.1-1, 045	A
CRDM head penetration nozzles: housings	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A
CRDM head penetration nozzles: housings	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.A2.R-413	3.1-1, 116	E
CRDM pressure housing: latch housing, travel housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
CRDM pressure housing: latch housing, travel housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
CRDM pressure housing: latch housing, travel housing	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-55	3.1-1, 047	A
CRDM pressure housing: latch housing, travel housing	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A
O-ring leak monitor tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	IV.A2.R-74b	3.1-1, 139	A
O-ring leak monitor tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A
O-ring leak monitor tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-103d	3.2-1, 007	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
O-ring leak monitor tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	IV.C2.R-452c	3.1-1, 136	A
Penetrations: head vent pipe nozzle	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A
Penetrations: vent pipe extension	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
Penetrations: vent pipe extension	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Penetrations: vent pipe extension	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-234	3.1-1, 046	C
Penetrations: vent pipe extension	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	C

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Penetrations: vent pipe nozzle	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
Penetrations: vent pipe nozzle	Pressure boundary	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	IV.A2.R-90	3.1-1, 045	A
Reactor vessel closure flange assembly components: studs, nuts, washers	Pressure boundary	High-strength steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.A2.RP-54	3.1-1, 001	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor vessel closure flange assembly components: studs, nuts, washers	Pressure boundary	High-strength steel	Air – indoor uncontrolled (ext)	Loss of material	Reactor Head Closure Stud Bolting	IV.A2.RP-53	3.1-1, 092	A
Reactor vessel closure flange assembly components: studs, nuts, washers	Pressure boundary	High-strength steel	Air – indoor uncontrolled (ext)	Cracking	Reactor Head Closure Stud Bolting	IV.A2.RP-52	3.1-1, 092	A
Reactor vessel closure flange assembly components: studs, nuts, washers	Pressure boundary	High-strength steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.A2.R-17	3.1-1, 049	A
Reactor vessel components subject to fatigue	Pressure boundary	Carbon steel (with stainless steel or nickel alloy clad), stainless steel, nickel alloy	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.A2.R-219	3.1-1, 010	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor vessel components: closure head, shells	Pressure boundary	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Reactor vessel components: closure head, shells	Pressure boundary	Carbon steel with stainless steel clad	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.A2.R-17	3.1-1, 049	A
Reactor vessel components: closure head, shells	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-234	3.1-1, 046	C
Reactor vessel components: lower shell	Pressure boundary	Carbon steel with nickel alloy clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Reactor vessel components: lower shell	Pressure boundary	Carbon steel with nickel alloy clad	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.A2.R-17	3.1-1, 049	A
Reactor vessel components: lower shell	Pressure boundary	Carbon steel with nickel alloy clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-234	3.1-1, 046	C

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor vessel components: lower shell	Pressure boundary	Carbon steel with nickel alloy clad	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A
Reactor vessel components: lower shell	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A
Reactor vessel components: primary nozzle safe ends	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	C
Reactor vessel components: primary nozzle safe ends	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Reactor vessel components: primary nozzle safe ends	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-234	3.1-1, 046	A
Reactor vessel components: primary nozzle safe ends	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor vessel components: primary nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Neutron flux	Loss of fracture toughness	TLAA – Section 4.2, Reactor Vessel Neutron Embrittlement Analysis	IV.A2.R-84	3.1-1, 013	A
Reactor vessel components: primary nozzles, bottom head, vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Reactor vessel components: primary nozzles, bottom head, vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.A2.R-17	3.1-1, 049	A
Reactor vessel components: primary nozzles, bottom head, vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.A2.RP-234	3.1-1, 046	C
Reactor vessel components: primary nozzles, bottom head, vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor vessel components: primary nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Neutron flux	Loss of fracture toughness	TLAA – Section 4.2, Reactor Vessel Neutron Embrittlement Analysis	IV.A2.R-84	3.1-1, 013	A
Reactor vessel components: primary nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Neutron flux	Loss of fracture toughness	Reactor Vessel Material Surveillance Neutron Fluence Monitoring	IV.A2.RP-229	3.1-1, 014	A
Reactor vessel components: shells	Pressure boundary	Carbon steel with stainless steel clad	Neutron flux	Loss of fracture toughness	TLAA – Section 4.2, Reactor Vessel Neutron Embrittlement Analysis	IV.A2.R-84	3.1-1, 013	A
Reactor vessel components: shells	Pressure boundary	Carbon steel with stainless steel clad	Neutron flux	Loss of fracture toughness	Reactor Vessel Material Surveillance Neutron Fluence Monitoring	IV.A2.RP-229	3.1-1, 014	A
Reactor vessel components: primary nozzles, shells, bottom head torus, vessel flange	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Crack growth	TLAA – Section 4.7, Other Plant-Specific TLAAs	IV.A2.R-85	3.1-1, 018	A

Table 3.1.2-3: Reactor Vessels — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor vessel components: vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.A2.RP-54	3.1-1, 001	A
Reactor vessel components: vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	Reactor Head Closure Stud Bolting	IV.A2.RP-53	3.1-1, 092	A
Reactor vessel components: vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.A2.R-87	3.1-1, 037	A

Notes for Table 3.1.2-3

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Table 3.1.2-4
Reactor Vessel Internals — Summary of Aging Management Evaluation

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor vessel internals components with metal fatigue analyses	All	All	All	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.B2.RP-303	3.1-1, 003	A
Lower core plate	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of material	Reactor Vessel Internals	IV.B2.RP-288	3.1-1, 059c	A
Lower core plate	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-289	3.1-1, 053c	A
Lower core plate	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Lower core plate	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.R-423	3.1-1, 118	E, I, 1
Lower core plate	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Fuel alignment pins	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Fuel alignment pins	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.R-423	3.1-1, 118	I, 1
Fuel alignment pins	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions Loss of material	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Lower support forging	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Lower support forging	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	None	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
Lower support columns	Core support Guide instrumentation	CASS	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.R-423	3.1-1, 118	E, I, 1
Lower support columns	Core support Guide instrumentation	CASS	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.RP-290	3.1-1, 059b	A
Lower support columns	Core support Guide instrumentation	CASS	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Lower support columns	Core support Guide instrumentation	CASS	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Lower support columns	Core support Guide instrumentation	CASS	Reactor coolant Neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
Lower support column bolting	Core support Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.RP-286	3.1-1, 053b	A
Lower support column bolting	Core support Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of preload	Reactor Vessel Internals	IV.B2.RP-287	3.1-1, 059b	A
Lower support column bolting	Core support Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Lower support column bolting	Core support Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions Loss of material	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
Lower support column bolting	Core support Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A
Radial keys	Core support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Radial keys	Core support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A
Diffuser plate	Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Diffuser plate	Flow distribution	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
Secondary core support	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Secondary core support	Core support Flow distribution Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
BMI column bodies	Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.RP-292	3.1-1, 059b	A
BMI column bodies	Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.RP-293	3.1-1, 053b	A
BMI column bodies	Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
BMI column bodies	Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.R-423	3.1-1, 118	E, I, 1
BMI column bodies	Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
Bottom-mounted instrumentation bases and extension bars	Guide instrumentation	CASS Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Bottom-mounted instrumentation bases and extension bars	Guide instrumentation	CASS Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
Head cooling spray nozzles	Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Head cooling spray nozzles	Flow distribution	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
Clevis insert	Core support	Nickel alloy	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Clevis insert	Core support	Nickel alloy	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A
Upper core plate alignment pins	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-299	3.1-1, 059c	A
Upper core plate alignment pins	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.RP-301	3.1-1, 053c	A
Upper core plate alignment pins	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.R-423	3.1-1, 118	E, I, 1
Upper core plate alignment pins	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Internals hold down spring	Core support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-300	3.1-1, 059a	I, 1
Internals hold down spring	Core support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Internals hold down spring	Core support	Stainless steel	Reactor coolant Neutron flux	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Head/vessel alignment pins	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Head/vessel alignment pins	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
Clevis insert bolting	Core support	Nickel alloy	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-285	3.1-1, 059c	I, 1
Clevis insert bolting	Core support	Nickel alloy	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.RP-399	3.1-1, 053c	I, 1
Clevis insert bolting	Core support	Nickel alloy	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Core barrel flange	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-345	3.1-1, 059c	A
Core barrel flange	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Core barrel flange	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.R-423	3.1-1, 118	I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Core barrel flange (upper weld)	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A
Core barrel outlet nozzle welds	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-278	3.1-1, 053b	A
Core barrel outlet nozzle welds	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Core barrel outlet nozzle welds	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
Lower core barrel (flange weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.RP-280	3.1-1, 053a	I, 1
Lower core barrel (axial weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-387a	3.1-1, 053b	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Lower core barrel (girth weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-387	3.1-1, 053a	A
Lower core barrel (axial weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.RP-388a	3.1-1, 059b	A
Lower core barrel (girth, flange, axial weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
Lower core barrel	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Upper core barrel (girth weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.RP-387	3.1-1, 053a	I, 1
Upper core barrel (girth weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.RP-388	3.1-1, 059a	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Upper core barrel (axial weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-387a	3.1-1, 053b	A
Upper core barrel (axial weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.RP-388a	3.1-1, 059b	A
Upper core barrel (girth, axial weld)	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
Upper core barrel	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
Upper core barrel	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Thermal shield	Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Thermal shield	Shield vessel	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
Thermal shield flexure	Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.RP-302	3.1-1, 053a	A
Thermal shield flexure	Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-302a	3.1-1, 059a	A
Thermal shield flexure	Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Thermal shield flexure	Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry	IV.B2.R-423	3.1-1, 118	E, I, 1
Thermal shield flexure	Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of preload	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
Baffle and former assembly: baffle and former plates	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Baffle and former assembly: baffle and former plates	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Baffle and former assembly: baffle and former plates	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals	IV.B2.RP-270	3.1-1, 059a	A
Baffle-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.RP-271	3.1-1, 053a	A
Baffle-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions Loss of preload	Reactor Vessel Internals	IV.B2.RP-272	3.1-1, 059a	A
Baffle-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Baffle-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
Baffle-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Baffle edge bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-275	3.1-1, 053a	A
Baffle edge bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions Loss of preload	Reactor Vessel Internals	IV.B2.RP-354	3.1-1, 059a	A
Baffle edge bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Baffle edge bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
Baffle edge bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Barrel-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-273	3.1-1, 053b	A
Barrel-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions Loss of preload	Reactor Vessel Internals	IV.B2.RP-274	3.1-1, 059b	A
Barrel-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Barrel-to-former bolts	Core support Flow distribution Shield vessel	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
Upper support plate	Core support Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Upper support plate	Core support Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Upper support ring	Core support Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Upper support ring	Core support Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-346	3.1-1, 053c	A
Upper core plate	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-290b	3.1-1, 059b	A
Upper core plate	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.RP-291b	3.1-1, 053b	A
Upper core plate	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Upper core plate	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.R-423	3.1-1, 118	E, I, 1
Upper core plate	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Upper core plate	Core support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A
Upper support columns bases	Core support Guide RCCAs Guide instrumentation	CASS	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Upper support columns bases	Core support Guide RCCAs Guide instrumentation	CASS	Reactor coolant Neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
Upper support columns	Core support Guide RCCAs Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Upper support columns	Core support Guide RCCAs Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	None	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	I, 1
Upper support column bolting	Core support Guide RCCAs Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Upper support column bolting	Core support Guide and Support RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.B2.RP-382	3.1-1, 032	A
Upper instrumentation column (thermocouple support tubes)	Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Upper instrumentation column (thermocouple support tubes)	Guide instrumentation	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
GTA lower flange (welds)	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.RP-298	3.1-1, 053a	A
GTA lower flange	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
GTA lower flange	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.R-423	3.1-1, 118	E, I, 1
GTA lower flange	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals	IV.B2.RP-297	3.1-1, 059a	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Guide cards	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-296	3.1-1, 059a	A
Guide cards	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Guide cards	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals Water Chemistry (for SCC mechanisms only)	IV.B2.R-423	3.1-1, 118	E, I, 1
Guide tubes	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Guide tubes	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
GTA sheath	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
GTA sheath	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A
Guide support pins	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.RP-355	3.1-1, 053c	I, 1
Guide support pins	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals	IV.B2.RP-356	3.1-1, 028	A

Table 3.1.2-4: Reactor Vessel Internals — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Guide support pins	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
Guide support pins	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals	IV.B2.R-423	3.1-1, 118	E, I, 1
Guide support pins	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of preload	Reactor Vessel Internals	IV.B2.R-424	3.1-1, 119	E, I, 1
GTA bolting	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	Loss of material	Water Chemistry	IV.B2.RP-24	3.1-1, 087	A
GTA bolting	Guide RCCAs	Stainless steel	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals	IV.B2.RP-265	3.1-1, 055c	A

Notes for Table 3.1.2-4

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

Plant-Specific Notes for Table 3.1.2-4

1. The aging effects identified for this item did not all screen in as applicable for an 80-year operating period. The component specific aging effect screening for reactor vessel internals is included in Appendix C, where further information is provided for each component and aging effect.

Table 3.1.2-5
Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Anti-vibration bars	Structural support	Nickel alloy with chrome plating	Treated water > 140°F Steam	Cracking	Steam Generators Water Chemistry	IV.D1.RP-384	3.1-1, 071	A
Anti-vibration bars	Structural support	Nickel alloy with chrome plating	Treated water Steam	Loss of material	Steam Generators	IV.D1.RP-225	3.1-1, 076	A
Anti-vibration bars	Structural support	Nickel alloy with chrome plating	Treated water Steam	Loss of material	Steam Generators Water Chemistry	IV.D1.RP-226	3.1-1, 071	A
Blowdown piping	Structural integrity (attached)	Carbon steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Blowdown piping nozzles	Pressure boundary	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	A
Blowdown piping nozzles	Pressure boundary	Alloy steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A
Blowdown piping nozzles	Pressure boundary	Alloy steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Blowdown piping nozzles	Pressure boundary	Alloy steel	Treated water	Wall thinning - FAC	Flow-Accelerated Corrosion	IV.D1.R-37	3.1-1, 061	C

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry Steam Generators	IV.D1.R-436	3.1-1, 127	A
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.D1.RP-232	3.1-1, 033	C
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Divider plate	Direct flow	Nickel alloy	Reactor coolant	Cracking	Water Chemistry Steam Generators	IV.D1.RP-367	3.1-1, 025	E
Divider plate	Direct flow	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Feedwater nozzle	Pressure boundary	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Feedwater nozzle	Pressure boundary	Alloy steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Feedwater nozzle	Pressure boundary	Alloy steel	Treated water	Wall thinning	Flow-Accelerated Corrosion	IV.D1.R-37	3.1-1, 061	A
Feedwater ring	Pressure boundary Structural Integrity (attached)	Carbon steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Feedwater ring	Pressure boundary Structural Integrity (attached)	Carbon steel	Treated water	Wall thinning	Steam Generators Water Chemistry	IV.D1.RP-49	3.1-1, 074	A
Flow distribution baffle	Direct flow	Stainless steel	Treated water	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	C
Flow distribution baffle	Direct flow	Stainless steel	Treated water > 140°F	Cracking	Steam Generators Water Chemistry	IV.D1.RP-384	3.1-1, 071	A
J-tubes	Direct flow Structural Integrity (attached)	Nickel alloy	Treated water > 140°F	Cracking	Steam Generators Water Chemistry	IV.D1.RP-384	3.1-1, 071	C

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
J-tubes	Direct flow Structural Integrity (attached)	Nickel alloy	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-226	3.1-1, 071	C
Lower shell	Pressure boundary	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Lower shell	Pressure boundary	Alloy steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A
Lower shell	Pressure boundary	Alloy steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	A
Moisture separators	Structural integrity (attached)	Carbon steel	Treated water Steam	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Moisture separators	Structural integrity (attached)	Carbon steel	Treated water Steam	Wall thinning	Steam Generators Water Chemistry	IV.D1.RP-49	3.1-1, 074	A
Primary manway bolting	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	IV.D1.RP-46	3.1-1, 067	A
Primary manway bolting	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	IV.D1.RP-166	3.1-1, 064	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Primary manway bolting	Pressure boundary	Low-alloy steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.C2.RP-167	3.1-1, 049	A
Primary manways (with disc insert)	Pressure boundary	Carbon steel with stainless steel insert	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Primary manways (with disc insert)	Pressure boundary	Carbon steel with stainless steel insert	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A
Primary manways (with disc insert)	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.D1.RP-232	3.1-1, 033	A
Primary manways (with disc insert)	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	C
Primary nozzle safe ends	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-452b	3.1-1, 136	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Primary nozzle safe ends	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Primary nozzle safe ends	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.D1.RP-232	3.1-1, 033	A
Primary nozzle safe ends	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
Secondary closure bolting	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	IV.D1.RP-166	3.1-1, 064	A
Secondary closure bolting	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	IV.D1.RP-46	3.1-1, 067	A
Secondary closure bolting	Pressure boundary	Low-alloy steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.C2.RP-167	3.1-1, 049	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Secondary closures: manway, access openings, inspection port and handholes	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Secondary closures: manway, access openings, inspection port and handholes	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A
Secondary closures: manway, access openings, inspection port and handholes	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	IV.D1.R-31	3.1-1, 044	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Secondary closures: manway, access openings, inspection port and handholes	Pressure boundary	Carbon steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Secondary side shell penetrations	Pressure boundary	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Secondary side shell penetrations	Pressure boundary	Alloy steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A
Secondary side shell penetrations	Pressure boundary	Alloy steel	Treated water Steam	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	A
Seismic support lugs	Structural support	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Seismic support lugs	Structural support	Alloy steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steam flow limiter	Throttle	Carbon steel	Steam	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Steam generator components with fatigue analysis	Pressure boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.D1.R-221	3.1-1, 008	A
Steam generator components with fatigue analysis	Pressure boundary	Steel with stainless steel cladding	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.D1.R-221	3.1-1, 008	A
Steam generator components with fatigue analysis	Pressure boundary	Nickel alloy	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.D1.R-46	3.1-1, 002	C
Steam generator components with fatigue analysis	Pressure boundary	Steel	Treated water Steam	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.D1.R-33	3.1-1, 005	A
Steam generator tube plugs	Pressure boundary	Nickel alloy	Reactor coolant	Cracking	Steam Generators Water Chemistry	IV.D1.R-40	3.1-1, 070	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steam generator tube plugs	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	C
Steam outlet nozzle	Pressure boundary	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	A
Steam outlet nozzle	Pressure boundary	Alloy steel	Steam	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Steam outlet nozzle	Pressure boundary	Alloy steel	Steam	Wall thinning	Flow-Accelerated Corrosion	IV.D1.R-37	3.1-1, 061	A
Support pads	Structural support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Support pads	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	IV.D1.R-17	3.1-1, 049	A
Transition cone	Pressure boundary	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Transition cone (original welds)	Pressure boundary	Alloy steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Water Chemistry	IV.D1.RP-368	3.1-1, 012	A
Transition cone (new welds)	Pressure boundary	Alloy steel	Treated water	Loss of material	One-Time Inspection Water Chemistry	IV.D1.RP-368	3.1-1, 012	E
Tube bundle wrapper	Direct flow Structural support	Carbon steel	Treated water Steam	Loss of material	Steam Generators Water Chemistry (general, pitting, crevice corrosion only)	IV.D1.RP-161	3.1-1, 072	A
Tube support plates	Structural support	Stainless steel	Treated water > 140°F Steam	Cracking	Steam Generators Water Chemistry	IV.D1.RP-384	3.1-1, 071	A
Tube support plates	Structural support	Stainless steel	Treated water Steam	Loss of material	Steam Generators Water Chemistry	IV.D1.RP-226	3.1-1, 071	A
Tubesheet	Pressure boundary	Alloy steel	Treated water	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	C
Tubesheet	Pressure boundary	Alloy steel with nickel alloy clad	Reactor coolant	Loss of material	Water Chemistry Steam Generators	IV.D1.R-436	3.1-1, 127	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Upper shell and elliptical head	Pressure boundary	Alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	IV.C2.R-431	3.1-1, 124	C
Upper shell and elliptical head	Pressure boundary	Alloy steel	Treated water Steam	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-372	3.1-1, 083	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant	Cracking	Steam Generators Water Chemistry	IV.D1.R-44	3.1-1, 070	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.D1.R-46	3.1-1, 002	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry	IV.C2.RP-23	3.1-1, 088	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water > 140°F Steam	Cracking	Steam Generators	IV.D1.R-437	3.1-1, 125	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water > 140°F Steam	Cracking	Steam Generators Water Chemistry	IV.D1.R-47	3.1-1, 069	A

Table 3.1.2-5: Steam Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water Steam	Loss of material	Steam Generators	IV.D1.RP-233	3.1-1, 077	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water Steam	Loss of material	Water Chemistry One-Time Inspection	IV.D1.RP-226	3.1-1, 071	C
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water Steam	Loss of material	Steam Generators Water Chemistry	IV.D1.R-50	3.1-1, 073	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water Steam	Reduction of heat transfer	Water Chemistry Steam Generators	IV.D1.R-407	3.1-1, 111	A

Notes for Table 3.1.2-5

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

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.

- Emergency Containment Cooling (Section 2.3.2.1)
- Containment Spray (Section 2.3.2.2)
- Containment Isolation (Section 2.3.2.3)
- Safety Injection (Section 2.3.2.4)
- Residual Heat Removal (Section 2.3.2.5)
- Containment Post Accident Monitoring and Control (Section 2.3.2.6)

3.2.2 Results

The following tables summarize the results of the aging management review for Engineered Safety Features.

Table 3.2.2-1, Emergency Containment Cooling – Summary of Aging Management Evaluation

Table 3.2.2-2, Containment Spray – Summary of Aging Management Evaluation

Table 3.2.2-3, Containment Isolation – Summary of Aging Management Evaluation

Table 3.2.2-4, Safety Injection – Summary of Aging Management Evaluation

Table 3.2.2-5, Residual Heat Removal – Summary of Aging Management Evaluation

Table 3.2.2-6, Containment Post Accident Monitoring and Control – Summary of Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Emergency Containment Cooling

Materials

The materials of construction for emergency containment cooling are:

- Carbon steel
- Copper alloy >15% Zn
- Galvanized steel

Environments

The emergency containment cooling components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation
- Treated water

Aging Effects Requiring Management

The following aging effects associated with emergency containment cooling require management:

- 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 Containment Cooling components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Selective Leaching

3.2.2.1.2 Containment Spray

Materials

The materials of construction for containment spray are:

- Carbon steel
- Cast iron
- CASS
- Coating
- Copper alloy
- Copper alloy >15% Zn
- Stainless steel

Environments

The containment spray components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water
- Treated borated water

Aging Effects Requiring Management

The following aging effects associated with containment spray require management:

- Cracking
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the containment spray components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks
- Selective Leaching
- One-Time Inspection
- Water Chemistry

3.2.2.1.3 Containment Isolation

Materials

The materials of construction for containment isolation are:

- Carbon steel
- Galvanized steel
- Stainless steel

Environments

The containment isolation components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects associated with containment isolation require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the containment isolation components:

- Bolting Integrity
- Boric Acid Corrosion
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

3.2.2.1.4 Safety Injection

Materials

The materials of construction for safety injection are:

- Carbon steel
- Carbon steel with stainless steel cladding
- Cast iron
- Coating
- Copper alloy >15% Zn
- Gray cast iron
- Nickel alloy
- Stainless steel

Environments

The safety injection components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Air – outdoor
- Concrete
- Gas
- Lubricating oil
- Treated water
- Treated borated water
- Underground

Aging Effects Requiring Management

The following aging effects associated with safety injection require management:

- Cracking
- 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 safety injection components:

- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping and Tanks
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks
- Lubricating Oil Analysis
- Selective Leaching
- One-Time Inspection
- Outdoor and Large Atmospheric Metallic Storage Tanks
- Water Chemistry

3.2.2.1.5 Residual Heat Removal

Materials

The materials of construction for residual heat removal are:

- Carbon steel
- Stainless steel
- CASS

Environments

The residual heat removal components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Treated water
- Treated borated water
- Treated borated water >140°F

Aging Effects Requiring Management

The following aging effects associated with residual heat removal require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the residual heat removal components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systemss
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- Water Chemistry

3.2.2.1.6 Containment Post Accident Monitoring and Control

Materials

The materials of construction for containment post accident monitoring and control are:

- Carbon Steel
- Copper Alloy
- Stainless steel

Environments

The containment post accident monitoring and control components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Gas
- Treated water
- Treated borated water

Aging Effects Requiring Management

The following aging effects associated with containment post accident monitoring and control require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the containment post accident monitoring and control components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- Water Chemistry

3.2.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Engineered Safety Features, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.2.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage of Engineered Safety Features components, as described in SRP-SLR Item 3.2.2.2.1, is addressed in Section 4.3.2, Metal Fatigue of Piping Components.

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.*

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.

Loss of material due to pitting and crevice corrosion is not an aging effect requiring management provided 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.

The only stainless steel components exposed to outdoor air in the Engineered Safety Features systems are piping and piping components associated with the refueling water storage tank in the Safety Injection system. There are no stainless steel tanks exposed to an outdoor air environment in the scope of subsequent license renewal at Turkey Point. Additional stainless steel piping, piping components, and heat exchanger components are exposed to an uncontrolled indoor air environment. The only nickel alloy included in the Engineered Safety Features systems is internal to heat exchangers and is not exposed to an air environment. A review of Turkey Point operating experience confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air in the Engineered Safety Features systems are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program.

Consistent with the recommendation of NUREG-2191, loss of material of these components will be managed via the External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs are described in Section B.2.3.23 and Section B.2.3.25, respectively.

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) portions of the system that are normally dry but subject to periodic wetting are identified; (b) plant-specific procedures exist to drain the normally dry portions that have been wetted during normal plant operation or inadvertently; (c) the plant-specific configuration of the drains and piping allow sufficient draining to empty the normally dry pipe; (d) plant-specific OE has not revealed loss of material or flow blockage due to fouling; and (e) a one-time inspection is conducted to verify that loss of material or flow blockage due to fouling has not occurred. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to conduct the one-time inspections. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage loss of material due to general corrosion and flow blockage due to fouling when the above conditions are not met.

This item is not applicable to Turkey Point as it only applies to drywell and suppression chamber spray nozzles in BWRs.

3.2.2.2.4 Cracking due to Stress Corrosion Cracking (SCC) 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 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.

Stress corrosion cracking is not an aging effect requiring management provided 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.*

The only stainless steel components exposed to outdoor air in the Engineered Safety Features systems are bolting, piping and piping components associated with the refueling water storage tank in the Safety Injection system. There are no stainless steel tanks exposed to an outdoor air environment in the scope of subsequent license renewal at Turkey Point. Additional stainless steel bolting, piping, piping components, and heat exchanger components are exposed to an uncontrolled indoor air environment. The only nickel alloy included in the Engineered Safety Features systems is internal to heat exchangers and is not exposed to an air environment. A review of Turkey Point operating experience confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air in the Engineered Safety Features systems are susceptible to SCC and require management via an appropriate program.

Consistent with the recommendation of NUREG-2191, cracking of these components will be managed via the External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity, External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs are described in Appendix B.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B.

3.2.2.2.6 Ongoing Review of Operating Experience

The Operating Experience process and acceptance criteria are described in Appendix B.

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.

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. 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.

Turkey Point operating experience over the past 10 years shows no instances that meet the criteria of recurring internal corrosion for metals containing raw water, waste water, or treated water; therefore, recurring internal corrosion is not an applicable aging effect at Turkey Point. There is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP beyond the recommendations in GALL-SLR due to recurring internal corrosion.

3.2.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of subsequent license renewal (SLR), acceptance criteria for this further evaluation are being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect *requiring management unless it is demonstrated by 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.

As the Engineered Safety Features systems do not contain any aluminum or aluminum alloy components, cracking of aluminum alloys is not an applicable aging effect.

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.

Portions of the stainless steel piping in the Engineered Safety Features systems are exposed to or encased in concrete. Stainless steel piping in the Engineered Safety Features systems that is exposed to concrete is not susceptible to being exposed to groundwater and therefore has no aging effects that require management. There is no steel piping exposed to a concrete environment in the Engineered Safety Features systems.

Consistent with the recommendation of NUREG-2191, the stainless steel piping exposed to concrete and not exposed to groundwater does not have any aging effects; therefore, there are no aging management programs associated with the management of these components.

3.2.2.2.10 <u>Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys</u>

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 results of the plant-specific OE review shall be documented 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.

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.*

As the Engineered Safety Features systems do not contain any aluminum or aluminum alloy components, loss of material of aluminum alloys is not an applicable aging effect.

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Engineered Safety Features components:

- Section 4.3, Metal Fatigue

3.2.3 Conclusion

The Engineered Safety Features piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Engineered Safety Features System components are identified in the summaries in Section 3.2.2 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Engineered Safety Features components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.2-1
Summary of Aging Management Evaluations for the Engineered Safety Features

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 001	Stainless steel, steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.2.2.2.1)	Cumulative fatigue damage is an aging effect assessed by a fatigue TLAA. Further evaluation is documented in Section 3.2.2.2.1.
3.2-1, 002	There is no 3.2-1, 002 in NUREG-2192.				
3.2-1, 003	There is no 3.2-1, 003 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 (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191 for component types listed but is also used for stainless steel heat exchanger components. The External Surfaces Monitoring of Mechanical Components program will be used to manage loss of material of stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air. Further evaluation is documented in Section 3.2.2.2.2.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 005	Stainless steel orifice (miniflow recirculation when centrifugal HPSI pumps are used for normal charging) exposed to treated borated water	Loss of material due to erosion	AMP XI.M32, "One-Time Inspection"	No	Not used. The High Head Safety Injection (HHSI) pumps are not used for normal charging and the stainless steel orifices in these systems are not subjected to high-velocity flow during normal operation. Regardless, the safety injection pump recirculation line is subject to erosion but will be managed using the Flow-Accelerated Corrosion AMP as detailed in line 3.2-1, 065.
3.2-1, 006	This line item only applies to BWRs.				

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 007	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191 for component types listed but is also used for stainless steel heat exchanger components. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs will be used to manage loss of material of stainless steel piping, piping components, heat exchanger components, and tanks exposed to air internally and externally, respectively. Further evaluation is documented in Section 3.2.2.2.4.
3.2-1, 008	Copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Not applicable. There are no copper alloy (>15% Zn) piping or piping components exposed to air with borated water leakage in the 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 009	Steel external surfaces exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion AMP will be used to manage loss of material of steel surfaces exposed to air with borated water leakage.
3.2-1, 010	CASS piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Not applicable. The only CASS components exposed to treated borated water with temperatures greater than 250°C (482°F) are part of the reactor pressure boundary and are evaluated as part of the Reactor Coolant 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	Not applicable. None of the Engineered Safety Features systems are identified as susceptible to flow accelerated corrosion (FAC) in Turkey Point's FAC program.
3.2-1, 012	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There is no high-strength steel closure bolting in the 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 013	There is no 3.2-1, 013 in NUREG-2192.				
3.2-1, 014	Stainless steel, steel, nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage loss of material of stainless steel and steel closure bolting exposed to condensation or uncontrolled air environments.
3.2-1, 015	Metallic closure bolting exposed to any environment, soil underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage loss of preload of metallic closure bolting in any environment.
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	Not used. While treated water is present, the only treated water in the Engineered Safety Features systems is closed cooling water. As such, steel components exposed to closed treated water will be managed using the Closed Treated Water Systems AMP.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 017	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum piping or piping components in the Engineered Safety Features systems.
3.2-1, 018	There is no 3.2-1, 018 in NUREG-2192.				
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 for stainless steel heat exchanger tubes exposed to treated borated water. The Water Chemistry and One-Time Inspection AMPs will be used to manage reduction of heat transfer of stainless steel heat exchanger tubes exposed to treated borated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 020	Stainless steel, steel (with stainless steel or nickel alloy cladding) piping, piping components, tanks exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 for component types listed but is also used for stainless steel heat exchanger components. The Water Chemistry and One-Time Inspection AMPs will be used to manage cracking of stainless steel piping, piping components, and heat exchanger components exposed to treated borated water >60°C (>140°F).
3.2-1, 021	There is no 3.2-1, 021 in NUREG-2192.				
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. The Water Chemistry and One-Time Inspection AMPs will be used to manage loss of material in nickel alloy and stainless steel heat exchanger components, piping, piping components and tanks exposed to treated water or treated borated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
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 components in the Engineered Safety Features systems exposed to raw water.
3.2-1, 024	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no components in the Engineered Safety Features systems exposed to raw water.
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 components in the Engineered Safety Features systems exposed to raw water.
3.2-1, 026	There is no 3.2-1, 026 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 components in the Engineered Safety Features systems exposed to raw water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 028	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel piping or piping components in the Engineered Safety Features systems exposed to closed-cycle cooling water greater than 60°C (>140°F).
3.2-1, 029	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no steel piping or piping components in the Engineered Safety Features systems exposed to closed-cycle cooling water.
3.2-1, 030	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP will be used to manage loss of material in steel heat exchanger components exposed to treated water.
3.2-1, 031	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP will be used to manage loss of material in stainless steel heat exchanger components exposed to treated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 032	Copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP will be used to manage loss of material in copper alloy heat exchanger components exposed to treated water.
3.2-1, 033	Copper alloy, stainless steel heat exchanger tubes exposed to closed- cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP will be used to manage reduction of heat transfer in copper alloy and stainless steel heat exchanger tubes exposed to treated water.
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 AMP will be used to manage loss of material due to selective leaching in copper alloy (>15% Zn or >8% Al) heat exchanger components exposed to treated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 035	Gray cast iron motor cooler exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. The Selective Leaching AMP will be used to manage loss of material due to selective leaching in gray cast iron motor coolers exposed to treated water.
3.2-1, 036	Gray cast iron, ductile iron piping, piping components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no gray cast iron piping or piping components in the Engineered Safety Features systems.
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 piping or piping components in the 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	Not applicable. There are no elastomer piping, piping components, or seals in the Engineered Safety Features systems.
3.2-1, 039	There is no 3.2-1, 039 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
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 AMP will be used to manage loss of material in steel external surfaces exposed to condensation, outdoor air, and uncontrolled indoor air.
3.2-1, 041	There is no 3.2-1, 041 in NUREG-2192.				
3.2-1, 042	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no aluminum piping, piping components or tanks in the Engineered Safety Features systems.
3.2-1, 043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer piping, piping components, or seals in the 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 044	Steel piping, piping components, ducting, ducting components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be used to manage loss of material internal to steel piping, piping components, ducting, and ducting components exposed to uncontrolled indoor air.
3.2-1, 045	Steel encapsulation components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel encapsulation components exposed to uncontrolled indoor air in the 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 046	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 for material, environment, and aging management program. This line item is applied to steel heat exchanger components exposed to condensation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage the loss of material of steel heat exchanger components exposed to condensation.
3.2-1, 047	Steel encapsulation components exposed to air with borated water leakage	Loss of material due to general, pitting, crevice, boric acid corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel encapsulation components exposed to air with borated water leakage in the 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 048	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be used to manage loss of material of stainless steel piping, piping components, and tanks exposed to air internally. Further evaluation is documented in Section 3.2.2.2.2.
3.2-1, 049	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no steel piping or piping components exposed to lubricating oil in the 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 Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 050	Copper alloy, stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. The Engineered Safety Features systems do not include any copper alloy or stainless steel piping or piping components exposed to lubricating oil.
3.2-1, 051	Steel, copper alloy, stainless steel heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis and One-Time Inspection AMPs will be used to manage a reduction of heat transfer due to fouling for steel (specifically gray cast iron) exposed to lubricating oil.
3.2-1, 052	Steel piping, piping components exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features system does not include any buried or underground steel piping or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**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. The Engineered Safety Features system does not include any buried or underground piping or tanks exposed to soil or concrete. Note that underground piping in the safety injection system is in an underground trench and not directly exposed to soil or concrete. This piping is managed using the Buried and Underground Piping and Tanks AMP and is associated with item number 3.2-1, 080.
3.2-1, 053a	There is no 3.2-1, 053a in NUREG-2192.				
3.2-1, 054	This line item only applies to BWRs.				
3.2-1, 055	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not applicable. There are no steel piping or piping components exposed to concrete in the 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 Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 056	Aluminum piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP-XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features systems do not include any aluminum piping, piping components, or tanks.
3.2-1, 057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. Copper alloy piping, piping components, and heat exchanger components exposed to air, condensation or gas do not have any aging effects that require management.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 058	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not used. The environment and material combination do exist. However, this SLRA does not list combinations in the Table 2s that have no aging effects unless there is only one environment applicable to that component type and material.
3.2-1, 059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Consistent with NUREG-2191. This line item is used to recognize the lack of aging effects in galvanized steel components exposed to controlled indoor air.
3.2-1, 060	Glass piping elements exposed to air, underground, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for glass piping elements exposed to treated water or air.
3.2-1, 061	There is no 3.2-1, 061 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. The Engineered Safety Features systems do not include any nickel alloy piping or piping components exposed to air with borated water leakage.
3.2-1, 063	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191. Stainless steel piping and piping components exposed to gas do not have any aging effects that require management. While the environment and material combination do exist, the environment of air with borated water leakage is only considered for steel components.
3.2-1, 064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. This line item is used to recognize the lack of aging effects in steel components exposed to gas.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
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 AMP will be used to manage wall thinning due to erosion in stainless steel piping and piping components exposed to treated borated water. This line item only applies to the safety injection pump recirculation lines as identified by plant OE.
3.2-1, 066	Metallic piping, piping components, tanks exposed to raw water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.2.2.2.7)	Not applicable. There are no components in the Engineered Safety Features systems exposed to raw water or waste water. Based on a review of Turkey Point OE, there are no instances of recurring internal corrosion in the Engineered Safety Features systems. See Section 3.2.2.2.7 for further evaluation.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 067	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. The Engineered Safety Features systems do not include any stainless steel tanks within the scope of Outdoor and Large Atmospheric Metallic Storage Tanks AMP.
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	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP will be used to manage loss of material of the steel refueling water storage tanks exposed to outdoor air.
3.2-1, 069	Insulated steel piping, piping components, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. The Engineered Safety Features systems do not include any insulated steel piping, piping components, or tanks within the scope of Outdoor and Large Atmospheric Metallic Storage Tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	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	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP will be used to manage loss of material of the steel refueling water storage tanks exposed to treated borated water.
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. The Engineered Safety Features systems do not include any insulated copper alloy piping, piping components, or tanks.
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	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be used to manage loss of coating integrity where exposed to treated borated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	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	Not used. Material coatings and underlying materials have been addressed using the appropriate line items for coatings and the underlying materials.
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 used. Material coatings and underlying materials have been addressed using the appropriate line items for coatings and the underlying materials.
3.2-1, 075	There is no 3.2-1, 075 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 Program (AMP)/TLAA	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	Not applicable The Engineered Safety Features System does not contain any bolting exposed to treated water, treated borated water, raw water, waste water, or lubricating oil.
3.2-1, 077	There is no 3.2-1, 077 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	Not applicable. The Engineered Safety Features systems do not include any steel, stainless steel, or aluminum piping, piping components, or tanks that are exposed to soil or concrete and within the scope of the Buried and Underground Piping and Tanks AMP.
3.2-1, 079	Stainless steel closure bolting exposed to air, soil, concrete, underground	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage cracking of stainless steel closure bolting exposed to air, soil, or concrete.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 080	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP will be used to manage cracking of stainless steel underground piping.
3.2-1, 081	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191 for component, material, and aging effect. This line item is applied to heat exchanger tubes that are not accessible externally, therefore; a different program is used to manage them. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be used to manage reduction of heat transfer in copper heat exchanger tubes exposed to condensation.
3.2-1, 083	There is no 3.2-1, 083 in NUREG-2192.				
3.2-1, 084	There is no 3.2-1, 084 in NUREG-2192.				
3.2-1, 085	There is no 3.2-1, 085 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 Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 086	There is no 3.2-1, 086 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 Engineered Safety Features systems do not include any thermal insulation that is within the scope of SLR.
3.2-1, 089	There is no 3.2-1, 089 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 AMP will be used to manage long-term loss of material in the steel containment spray piping and the pressurizer relief tank exposed to treated borated water. The pressurizer relief tank is coated and the containment spray piping is normally empty.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 091	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Consistent with NUREG-2191. As the stainless steel piping exposed to concrete in the Engineered Safety Features systems is not also exposed to ground water, there are no aging effects that require management. Further evaluation is documented in Section 3.2.2.2.9.
3.2-1, 092	There is no 3.2-1, 092 in NUREG-2192.				
3.2-1, 095	There is no 3.2-1, 095 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. The Engineered Safety Features systems do not include stainless steel piping or piping components exposed to raw water.
3.2-1, 097	There is no 3.2-1, 097 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. The Engineered Safety Features systems do not include copper alloy piping or piping components exposed to soil.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 099	Stainless steel, nickel alloy tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Not applicable. The Engineered Safety Features systems do not include any stainless steel or nickel alloy tanks.
3.2-1, 100	Aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water, waste water	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features systems do not include any aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 101	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features systems do not include any aluminum piping, piping components or tanks.
3.2-1, 102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features systems do not include any aluminum tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 103	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32,"One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Not applicable. The Engineered Safety Features systems do not include any stainless steel tanks.
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. The Engineered Safety Features systems do not include any aluminum tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 105	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32,"One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features systems do not include any aluminum tanks.
3.2-1, 106	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Not applicable. The Engineered Safety Features systems do not include any stainless steel or nickel alloy tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 107	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage loss of material of insulated stainless steel piping, piping components, and piping elements exposed to air. Further evaluation is documented in Section 3.2.2.2.2.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 108	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage cracking of insulated stainless steel piping, piping components, and piping elements exposed to air. Further evaluation is documented in Section 3.2.2.2.4.
3.2-1, 109	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features systems do not include any insulated aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 110	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features systems do not include any aluminum piping, piping components, or tanks.
3.2-1, 111	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features systems do not include any aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 112	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP will be used to manage loss of material of stainless steel underground piping.
3.2-1, 113	There is no 3.2-1, 113 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	Not applicable. The Engineered Safety Features systems do not include any stainless steel or nickel alloy piping or piping components exposed to treated water >60°C (>140°F).
3.2-1, 115	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. The Engineered Safety Features systems do not include any titanium heat exchanger tubes.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 116	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. The Engineered Safety Features systems do not include any titanium heat exchanger components.
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. The Engineered Safety Features systems do not include any titanium heat exchanger tubes.
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. The Engineered Safety Features systems do not include any titanium heat exchanger components.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features systems do not include any insulated aluminum piping, piping components, or tanks.
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. The Engineered Safety Features systems do not include any aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 121	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features systems do not include any aluminum piping, piping components, or tanks.
3.2-1, 122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no elastomer piping, piping components, or seals in the Engineered Safety Features systems.
3.2-1, 123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer piping, piping components, or seals in the 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. The Engineered Safety Features systems do not include any aluminum piping, piping components, or tanks.
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. The Engineered Safety Features systems do not include any steel closure bolts exposed to soil, concrete, or underground.
3.2-1, 126	Titanium, super austenitic piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to pitting, crevice corrosion, MIC (except for titanium; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features systems do not include any titanium or super austenitic piping, piping components, tanks, or closure bolting.
3.2-1, 127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. The Engineered Safety Features systems do not include any copper alloy piping or piping components exposed to concrete.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 128	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features systems do not include any copper alloy piping or piping components exposed to soil or underground.
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. The Engineered Safety Features systems do not include any stainless steel tanks.
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 and One-Time Inspection AMPs will be used to manage loss of material for steel (specifically gray cast iron) exposed to lubricating oil.
3.2-1, 131	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. The Engineered Safety Features systems do not include any aluminum piping or piping components.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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 components in the Engineered Safety Features systems exposed to raw water.
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 components in the Engineered Safety Features systems exposed to raw water.
3.2-1, 134	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no polymeric components in the Engineered Safety Features systems.

Table 3.2.2-1
Emergency Containment Cooling —
Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Fan housing	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A

Table 3.2.2-1: Emergency Containment Cooling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.E-27	3.2-1, 046	C
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Condensation (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.E.E-424	3.2-1, 081	E
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	V.A.EP-100	3.2-1, 033	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Condensation (ext)	None	None	V.F.EP-10	3.2-1, 057	A

Table 3.2.2-1: Emergency Containment Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	V.A.EP-94	3.2-1, 032	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	V.A.EP-37	3.2-1, 034	A

Notes for Table 3.2.2-1

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and aging AMP for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Table 3.2.2-2
Containment Spray — Summary of Aging Management Evaluation

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	V.E.E-421	3.2-1, 079	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Filter	Filter	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Filter	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Flow element	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (bands and clips)	Structural support	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.A.EP-93	3.2-1, 031	B
Heat exchanger (coil shield)	Direct flow	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.A.EP-94	3.2-1, 032	B
Heat exchanger (coil shield)	Direct flow	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Selective Leaching	V.A.EP-37	3.2-1, 034	A
Heat exchanger (coil)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	V.A.E-20	3.2-1, 019	A
Heat exchanger (coil)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Heat exchanger (coil)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.A.EP-93	3.2-1, 031	B
Heat exchanger (shell)	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Cast iron	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Heat exchanger (shell)	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	V.A.EP-92	3.2-1, 030	B
Heat exchanger (shell)	Pressure boundary	Coating	Treated water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VII.C2.A-416	3.3-1, 138	A
Nozzle	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	A
Nozzle	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	V.F.EP-10	3.2-1, 057	A
Nozzle	Spray	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	A
Nozzle	Spray	Copper alloy	Air – indoor uncontrolled (int)	None	None	V.F.EP-10	3.2-1, 057	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-103d	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-81c	3.2-1, 048	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Piping	Pressure boundary	Carbon steel	Treated borated water (int)	Long-term loss of material	One-Time Inspection	V.A.E-434	3.2-1, 090	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	-	-	H, 1
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-103d	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-81c	3.2-1, 048	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Pump casing	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Tubing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A

Table 3.2.2-2: Containment Spray — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.A.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.A.EP-41	3.2-1, 022	A

Notes for Table 3.2.2-2

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

H. Aging effect not in NUREG-2191 for this component, material, and environment combination.

Plant-Specific Notes for Table 3.2.2-2

1. Aging effect for this component, material, and environment combination is not in NUREG-2191. This line item is specific to the carbon steel piping header for containment spray. This portion of piping is normally drained but is flooded during system testing. The Water Chemistry and One-Time Inspection AMPs are used to manage this aging effect as these AMPs are used to manage loss of material in other portions of the treated borated water systems. Note that long-term loss of material is addressed by GALL line item V.A.E-434 and is included in this AMR as well.

Table 3.2.2-3
Containment Isolation — Summary of Aging Management Evaluation

Table 3.2.2-3: Containment Isolation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	V.E.E-421	3.2-1, 079	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Filter element	Filter	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A

Table 3.2.2-3: Containment Isolation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter element	Filter	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter element	Filter	Galvanized steel	Air-indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Filter housing	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Filter housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Galvanized steel	Air-indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A

Table 3.2.2-3: Containment Isolation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-103d	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-81c	3.2-1, 048	A
Valve body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A

Table 3.2.2-3: Containment Isolation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-3: Containment Isolation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-103d	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.EP-81C	3.2-1, 048	A

Notes for Table 3.2.2-3

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.2.2-4
Safety Injection — Summary of Aging Management Evaluation

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	V.E.E-421	3.2-1, 079	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	V.E.E-421	3.2-1, 079	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger	Heat transfer	Gray cast iron	Lubricating oil (int)	Reduction of heat transfer	Lubricating Oil Analysis One-Time Inspection	V.D1.EP-75	3.2-1, 051	A
Heat exchanger	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Heat exchanger	Pressure boundary	Gray cast iron	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Heat exchanger	Pressure boundary	Gray cast iron	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	V.D1.E-473	3.2-1, 130	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	V.D1.EP-92	3.2-1, 030	B
Heat exchanger	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching	V.D1.E-43	3.2-1, 035	A
Heat exchanger	Pressure boundary	Gray cast iron	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.F2.AP-204	3.3-1, 050	B
Heat exchanger (bands and clips)	Structural support	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.D1.EP-93	3.2-1, 031	D
Heat exchanger (coil shield)	Direct flow	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.D1.EP-97	3.2-1, 032	D
Heat exchanger (coil shield)	Direct flow	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Selective Leaching	V.D1.EP-27	3.2-1, 034	C
Heat exchanger (coil)	Heat transfer	Nickel alloy	Treated borated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	-	-	H, 1
Heat exchanger (coil)	Heat transfer	Nickel alloy	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems	-	-	H, 2
Heat exchanger (coil)	Pressure boundary	Nickel alloy	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.E-428	3.2-1, 022	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (coil)	Pressure boundary	Nickel alloy	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.D1.E-428	3.2-1, 022	E, 3
Heat exchanger (shell)	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Heat exchanger (shell)	Pressure boundary	Cast iron	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Heat exchanger (shell)	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	V.D1.EP-92	3.2-1, 030	B
Heat exchanger (shell)	Pressure boundary	Coating	Treated water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	V.D1.E-401	3.2-1, 072	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Wall thinning	Flow-Accelerated Corrosion	V.D1.E-407	3.2-1, 065	A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Wall thinning	Flow-Accelerated Corrosion	V.D1.E-407	3.2-1, 065	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.E.E-451c	3.2-1, 108	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-450c	3.2-1, 107	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.E.E-451c	3.2-1, 108	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-450c	3.2-1, 107	A
Piping	Pressure boundary	Stainless steel	Concrete	None	None	V.F.EP-20	3.2-1, 091	A
Piping	Pressure boundary	Stainless steel	Underground	Cracking	Buried and Underground Piping and Tanks	V.E.E-423b	3.2-1, 080	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Underground	Loss of material	Buried and Underground Piping and Tanks	V.E.E-455b	3.2-1, 112	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Wall thinning	Flow-Accelerated Corrosion	V.D1.E-407	3.2-1, 065	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	V.D1.E-402	3.2-1, 068	A
Tank	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Tank	Pressure boundary	Carbon steel	Treated borated water (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	V.D1.E-404	3.2-1, 070	A
Tank	Pressure boundary	Carbon steel with stainless steel cladding	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Tank	Pressure boundary	Carbon steel with stainless steel cladding	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Tank	Pressure boundary	Carbon steel with stainless steel cladding	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Carbon steel with stainless steel cladding	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Tank	Pressure boundary	Coating	Treated borated water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	V.D1.E-401	3.2-1, 072	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	V.D1.E-402	3.2-1, 068	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Tubing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Tubing	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-4: Safety Injection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Wall thinning	Flow-Accelerated Corrosion	V.D1.E-407	3.2-1, 065	A

Notes for Table 3.2.2-4

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

H. Aging effect not in NUREG-2191 for this component, material, and environment combination.

Plant-Specific Notes for Table 3.2.2-4

1. The Water Chemistry and One-Time Inspection AMPs are used to manage reduction of heat transfer for stainless steel heat exchanger tubes via V.D1.E-20. As stainless steel and nickel alloy have the similar aging effects when exposed to treated

borated water, the Water Chemistry and One-Time Inspection AMPs are adequate to manage reduction of heat transfer for nickel alloy heat exchanger tubes exposed to treated borated water.

2. The Closed Treated Water Systems AMP is used to manage reduction of heat transfer for stainless steel heat exchanger tubes via V.D1.EP-96. As stainless steel and nickel alloy have the similar aging effects when exposed to treated water, the Closed Treated Water Systems AMP is adequate to manage reduction of heat transfer for nickel alloy heat exchanger tubes exposed to treated water.
3. The treated water environment for this component is part of the component cooling water (CCW) system. As CCW is a closed treated water system, the Closed Treated Water Systems AMP is appropriate for managing the aging effects.

Table 3.2.2-5
Residual Heat Removal — Summary of Aging Management Evaluation

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	V.E.E-421	3.2-1, 079	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Expansion joint	Expansion/ Separation	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	Expansion/ Separation	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Expansion joint	Expansion/ Separation	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Expansion joint	Expansion/ Separation	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	C

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	V.D1.EP-92	3.2-1, 030	B
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	C
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.D1.EP-93	3.2-1, 031	B

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	C
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	V.D1.E-20	3.2-1, 019	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.D1.EP-93	3.2-1, 031	B
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems	V.D1.EP-96	3.2-1, 033	B
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	B
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Orifice	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Orifice	Throttle	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.E.E-451c	3.2-1, 108	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-450c	3.2-1, 107	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Piping	Pressure boundary	Stainless steel	Concrete	None	None	V.F.EP-20	3.2-1, 091	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Piping	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Pressure boundary	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	V.D1.E-13	3.2-1, 001	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Pump casing	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Pump casing	Pressure boundary	CASS	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A
Strainer body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Strainer body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Strainer body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Strainer element	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Strainer element	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Thermowell	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Tubing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Tubing	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Valve body	Pressure boundary	CASS	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-5: Residual Heat Removal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Valve body	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	V.D1.E-12	3.2-1, 020	A

Notes for Table 3.2.2-5

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.2.2-6
Containment Post Accident Monitoring and Control —
Summary of Aging Management Evaluation

Table 3.2.2-6: Containment Post Accident Monitoring and Control — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	V.E.E-02	3.2-1, 014	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	V.E.E-421	3.2-1, 079	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	V.E.EP-116	3.2-1, 015	A
Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C

Table 3.2.2-6: Containment Post Accident Monitoring and Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	C
Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	V.D1.EP-93	3.2-1, 031	B
Heat exchanger (shell)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	C
Heat exchanger (shell)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	C
Heat exchanger (shell)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	V.D1.EP-93	3.2-1, 031	B
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	V.D1.EP-93	3.2-1, 031	B

Table 3.2.2-6: Containment Post Accident Monitoring and Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Piping	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	A
Piping	Pressure boundary	Copper alloy	Gas (int)	None	None	V.F.EP-10	3.2-1, 057	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-6: Containment Post Accident Monitoring and Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Tubing	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Tubing	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	A
Tubing	Pressure boundary	Copper alloy	Gas (int)	None	None	V.F.EP-10	3.2-1, 057	A

Table 3.2.2-6: Containment Post Accident Monitoring and Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Tubing	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Valve Body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.E.E-44	3.2-1, 040	A

Table 3.2.2-6: Containment Post Accident Monitoring and Control — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Valve Body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	V.E.E-28	3.2-1, 009	A
Valve Body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	A
Valve Body	Pressure boundary	Copper alloy	Gas (int)	None	None	V.F.EP-10	3.2-1, 057	A
Valve Body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	V.D1.EP-103c	3.2-1, 007	A
Valve Body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	V.D1.EP-107b	3.2-1, 004	A
Valve Body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-103d	3.2-1, 007	A

Table 3.2.2-6: Containment Post Accident Monitoring and Control — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.D1.EP-81c	3.2-1, 048	A
Valve Body	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A

Notes for Table 3.2.2-6

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

3.3 AGING MANAGEMENT OF AUXILIARY SYSTEMS

3.3.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.3.3, Auxiliary Systems, as being subject to AMR. The systems or portions of systems that are addressed in this section are described in the indicated sections.

- Intake Cooling Water (Section 2.3.3.1)
- Component Cooling Water (Section 2.3.3.2)
- Spent Fuel Pool Cooling (Section 2.3.3.3)
- Chemical and Volume Control (Section 2.3.3.4)
- Primary Water Makeup (Section 2.3.3.5)
- Primary Sampling (Section 2.3.3.6)
- Secondary Sampling (Section 2.3.3.7)
- Waste Disposal (Section 2.3.3.8)
- Plant Air (Section 2.3.3.9)
- Normal Containment Ventilation (Section 2.3.3.10)
- Auxiliary Building and Electrical Equipment Room Ventilation (Section 2.3.3.11.1)
- Control Building Ventilation (Section 2.3.3.11.2)
- Emergency Diesel Generator Building Ventilation (Section 2.3.3.11.3)
- Turbine Building Ventilation (Section 2.3.3.11.4)
- Fire Protection (Section 2.3.3.12)
- Emergency Diesel Generator Cooling Water (Section 2.3.3.13)
- Emergency Diesel Generator Air (Section 2.3.3.14)
- Emergency Diesel Generator Fuel and Lubrication Oil (Section 2.3.3.15)
- Auxiliary Systems in the Scope of 10 CFR 54.4(a)(2) for Spatial Interactions (Section 2.3.3.16)

3.3.2 Results

The following tables summarize the results of the AMR for Auxiliary Systems:

Table 3.3.2-1, Intake Cooling Water – Summary of Aging Management Evaluation

Table 3.3.2-2, Component Cooling Water – Summary of Aging Management Evaluation

Table 3.3.2-3, Spent Fuel Pool Cooling – Summary of Aging Management Evaluation (includes spent fuel pool cooling components requiring an AMR for 10 CFR 54.4(a)(2) spatial interactions)

Table 3.3.2-4, Chemical and Volume Control – Summary of Aging Management Evaluation (includes chemical and volume control components requiring an AMR for 10 CFR 54.4(a)(2) spatial interactions)

3.3.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Intake Cooling Water

Materials

The materials of construction for the Intake Cooling Water components are:

- Carbon steel
- Gray cast iron
- Coating
- Concrete
- Copper alloy
- Copper alloy >8% Al
- Ductile iron
- Elastomer
- Nickel alloy
- Stainless steel

Environments

The Intake Cooling Water components are exposed to the following environments:

- Air – outdoor
- Raw water
- Soil
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Intake Cooling Water components require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the Intake Cooling Water components:

- Bolting Integrity
- Buried and Underground Piping and Tanks
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks
- One-Time Inspection
- Open-Cycle Cooling Water System
- Selective Leaching

3.3.2.1.2 Component Cooling Water

Materials

The materials of construction for the Component Cooling Water components are:

- Carbon steel
- Copper alloy
- Copper alloy >15% Zn
- Copper alloy >8% Al
- Gray cast iron
- Stainless steel

Environments

The Component Cooling Water components are exposed to the following environments:

- Air with borated water leakage
- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Condensation
- Lubricating oil
- Raw water
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Component Cooling Water components require management:

- Cracking
- Flow blockage
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Component Cooling Water components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Open-Cycle Cooling Water System
- Selective Leaching

3.3.2.1.3 Spent Fuel Pool Cooling

Materials

The materials of construction for the Spent Fuel Pool Cooling components are:

- Carbon steel
- Stainless steel

Environments

The Spent Fuel Pool Cooling components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Treated borated water
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Spent Fuel Pool Cooling components require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Spent Fuel Pool Cooling components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- One-Time Inspection
- Water Chemistry

3.3.2.1.4 Chemical and Volume Control

Materials

The materials of construction for the Chemical and Volume Control components are:

- Carbon steel
- Copper alloy
- Copper alloy >15% Zn
- Gray cast iron
- Stainless steel

Environments

The Chemical and Volume Control components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Condensation
- Gas
- Lubricating oil
- Treated borated water
- Treated borated water >140 °F
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Chemical and Volume Control components require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Chemical and Volume Control components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Selective Leaching
- Water Chemistry

3.3.2.1.5 Primary Water Makeup

Materials

The materials of construction for the Primary Water Makeup components are:

- Carbon steel
- Stainless steel

Environments

The Primary Water Makeup components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Primary Water Makeup components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Primary Water Makeup components:

- Bolting Integrity
- Boric Acid Corrosion
- External Surfaces Monitoring of Mechanical Components
- One-Time Inspection
- Water Chemistry

3.3.2.1.6 Primary Sampling

Materials

The materials of construction for the primary sampling system components are:

- Carbon steel
- Stainless steel

Environments

The primary sampling system components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Condensation
- Treated borated water
- Treated borated water >140 °F
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the primary sampling 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 primary sampling system components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- Water Chemistry

3.3.2.1.7 Secondary Sampling

Materials

The materials of construction for the Secondary Sampling components are:

- Carbon steel
- Stainless steel

Environments

The Secondary Sampling components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Steam
- Treated water
- Treated water >140ºF

Aging Effect Requiring Management

The following aging effects associated with the Secondary Sampling components require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Secondary Sampling components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- One-Time Inspection
- Water Chemistry

3.3.2.1.8 Waste Disposal

Materials

The materials of construction for the Waste Disposal components are:

- Carbon steel
- Copper alloy
- Copper alloy >15% Zn
- Gray cast iron
- Stainless steel

Environments

The Waste Disposal components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Concrete
- Condensation
- Gas
- Treated borated water
- Treated water
- Waste water

Aging Effect Requiring Management

The following aging effects associated with the Waste Disposal components require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the Waste Disposal components:

- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping and Tanks
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- Selective Leaching
- Water Chemistry

3.3.2.1.9 Plant Air

Materials

The materials of construction for the Plant Air components are:

- Aluminum
- Carbon steel
- Copper alloy
- Stainless steel

Environments

The Plant Air components are exposed to the following environments:

- Air with borated water leakage
- Air – dry
- Air – indoor uncontrolled

- Air – outdoor
- Condensation
- Gas
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Plant Air components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Plant Air components:

- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping and Tanks
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

3.3.2.1.10 Normal Containment Cooling

Materials

The materials of construction for the Normal Containment Ventilation components are:

- Carbon steel
- Copper alloy >15% Zn
- Elastomer
- Galvanized steel
- Stainless steel

Environments

The Normal Containment Ventilation components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Concrete
- Condensation
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Normal Containment Ventilation components require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Normal Containment Ventilation components:

- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping and Tanks
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Selective Leaching

3.3.2.1.11 Auxiliary Building and Electrical Equipment Room Ventilation

Materials

The materials of construction for the Auxiliary Building and Electrical Equipment Room Ventilation components are:

- Carbon steel
- Elastomer
- Galvanized steel
- Stainless steel

Environments

The Auxiliary Building and Electrical Equipment Room Ventilation components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Condensation
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Auxiliary Building and Electrical Equipment Room Ventilation components require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Auxiliary Building and Electrical Equipment Room Ventilation components:

- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

3.3.2.1.12 Control Building Ventilation

Materials

The materials of construction for the Control Building Ventilation components are:

- Aluminum
- Carbon steel
- Copper alloy
- Elastomer
- Galvanized steel
- Stainless steel

Environments

The Control Building Ventilation components are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Condensation
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Control Building Ventilation components require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Control Building Ventilation components:

- Bolting Integrity
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

3.3.2.1.13 Emergency Diesel Generator Ventilation

Materials

The materials of construction for the Emergency Diesel Generator Ventilation components are:

- Carbon steel
- Galvanized steel
- Stainless steel

Environments

The Emergency Diesel Generator Ventilation components are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effect Requiring Management

The following aging effects associated with the Emergency Diesel Generator Ventilation components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Emergency Diesel Generator Ventilation components:

- Bolting Integrity
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

3.3.2.1.14 Turbine Building Ventilation

Materials

The materials of construction for the Turbine Building Ventilation components are:

- Aluminum
- Carbon steel
- Copper alloy
- Galvanized steel
- Glass
- Stainless steel

Environments

The Turbine Building Ventilation components are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Condensation
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Turbine Building Ventilation components require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Turbine Building Ventilation components:

- Bolting Integrity
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

3.3.2.1.15 Fire Protection

Materials

The materials of construction for the Fire Protection components are:

- Aluminum
- Carbon steel
- Copper alloy > 15% Zn
- Elastomer
- Galvanized steel
- Gray cast iron
- Stainless steel

Environments

The Fire Protection components are exposed to the following environments:

- Air with borated water leakage
- Air – dry
- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Fuel oil
- Gas
- Lubricating oil
- Raw water
- Soil
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Fire Protection components require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the Fire Protection components:

- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping and Tanks
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Fire Protection
- Fire Water System
- Fuel Oil Chemistry
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Selective Leaching

3.3.2.1.16 Emergency Diesel Generator Cooling Water

Materials

The materials of construction for the Emergency Diesel Generator Cooling Water components are:

- Aluminum
- Carbon steel
- Cast iron
- Copper alloy >15% Zn
- Elastomer
- Galvanized steel
- Glass
- Stainless steel

Environments

The Emergency Diesel Generator Cooling Water components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Treated water
- Treated water >140°F

Aging Effect Requiring Management

The following aging effects associated with the Emergency Diesel Generator Cooling Water components require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Emergency Diesel Generator Cooling Water components:

- Bolting Integrity
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Selective Leaching

3.3.2.1.17 Emergency Diesel Generator Air

Materials

The materials of construction for the Emergency Diesel Generator Air components are:

- Aluminum alloy
- Carbon steel
- CASS
- Cast iron
- Copper alloy
- Elastomer
- Galvanized steel
- Stainless steel

Environments

The Emergency Diesel Generator Air components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Diesel exhaust
- Lubricating oil

Aging Effect Requiring Management

The following aging effects associated with the Emergency Diesel Generator Air components require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Emergency Diesel Generator Air components:

- Bolting Integrity
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis

3.3.2.1.18 Emergency Diesel Generator Fuel and Lubrication Oil

Materials

The materials of construction for the Emergency Diesel Generator Fuel Oil and Lubrication Oil components are:

- Carbon steel
- CASS
- Cast iron
- Copper alloy
- Glass
- Stainless steel

Environments

The Emergency Diesel Generator Fuel Oil and Lubrication Oil components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Fuel oil
- Lubricating oil
- Treated water

Aging Effect Requiring Management

The following aging effects associated with the Emergency Diesel Generator Fuel Oil and Lubrication Oil components require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the Emergency Diesel Generator Fuel Oil and Lubrication Oil components:

- Bolting Integrity
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Fuel Oil Chemistry
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Outdoor and Large Atmospheric Metallic Storage Tanks

3.3.2.1.19 Service Water

Materials

The materials of construction for Service Water components are:

- Carbon steel
- Copper alloy

Environments

The Service Water components are exposed to the following environments:

- Air with borated water leakage
- Air – indoor uncontrolled
- Air – outdoor
- Raw water

Aging Effect Requiring Management

The following aging effects associated with Service Water components require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Service Water components:

- Bolting Integrity
- Boric Acid Corrosion
- External Surfaces Monitoring of Mechanical Components
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

3.3.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Auxiliary Systems, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.3.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage of Auxiliary Systems along with Steam and Power Conversion System components, as described in SRP-SLR Item 3.2.2.2.1, is addressed as a TLAA in Section 4.3.2, Metal Fatigue of Piping Components. Although not addressed in Auxiliary Systems or Steam and Power Conversion System, SRP item number 3.3-1, 001 related to structural components is evaluated as a TLAA in Section 4.7, Other Plant-Specific Time-Limited Aging Analyses.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

Cracking due to stress corrosion cracking (SCC) and cyclic loading could occur in stainless steel (SS) PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (Celsius) [140 °F (Fahrenheit)] in the chemical and volume control system. The existing AMP for monitoring and control of primary Water Chemistry in PWRs (GALL-SLR Report AMP XI.M2, "Water Chemistry") manages the aging effects of cracking due to SCC. However, control of Water Chemistry does not preclude cracking due to SCC and cyclic loading. Therefore, the effectiveness of the Water Chemistry control program should be verified to ensure that cracking is not occurring. If a search of plant-specific operating experience (OE) does not reveal that *cracking has occurred in nonregenerative heat exchanger tubing, this aging effect can be considered to be adequately managed by GALL-SLR Report AMP XI.M2. However, if cracking has occurred in nonregenerative heat exchanger tubing, the GALL-SLR Report recommends that AMP XI.M21A, "Closed Treated Water Systems," be evaluated for inclusion of augmented requirements to conduct temperature and radioactivity monitoring of the shell side water, and where component configuration permits, periodic eddy current testing of tubes.*

Based on a review of Turkey Point OE, there is no evidence of cracking of non-regenerative heat exchanger tubes. This confirms the adequacy of the Water Chemistry program as described in the above text from GALL-SLR. Consistent with the recommendation of NUREG-2191, the Water Chemistry program will be used to manage cracking due to SCC and cyclic loading in stainless steel nonregenerative heat exchanger tubing.

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 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.

Stress corrosion cracking is not an aging effect requiring management provided 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.

Auxiliary Systems contain stainless steel bolting, piping, piping components, ducting, ducting components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air as well as outdoor air. A review of Turkey Point OE confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, stainless steel components exposed to indoor and outdoor air in Auxiliary Systems are susceptible to cracking due to SCC and require management with an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed by the Bolting Integrity, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and the External Surfaces Monitoring of Mechanical Components program for components exposed to air internally or externally, respectively. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and External Surfaces Monitoring of Mechanical Components AMPs are described in Appendix B.

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.

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.

Pitting and crevice corrosion is not an aging effect requiring management provided 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.

Auxiliary Systems contain stainless steel piping, piping components, ducting, ducting components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air as well as outdoor air. A review of Turkey Point OE confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air in the Auxiliary Systems are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material in these components will be managed via the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and the External Surfaces Monitoring of Mechanical Components AMP for components exposed to air internally or externally, respectively. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs are described in Appendix B.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2 of this SRP-SLR.)

Quality Assurance provisions applicable to SLR are discussed in Appendix B.

3.3.2.2.6 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The Operating Experience process and acceptance criteria are described in Appendix B.

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.

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.

Site OE over the past 10 years shows some limited recurrence of external corrosion for mechanical components from leakage and an instance of > 50% wall loss in heat exchanger tubes. However, there have been no corrosion issues that meet the criteria of recurring internal corrosion. Therefore, recurring internal corrosion is not an applicable aging effect for metals in Turkey Point systems containing raw water or waste water. As such, credited Turkey Point AMPs, such as Fire Water System, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Open-Cycle Cooling Water System, do not require augmentation for detection of aging effects prior to functional impact. Furthermore, there are no lines that contain non-refrigerant treated water in the Turkey Point Fire Protection system (system 016).

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 one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to *determine the alloy is not susceptible and technical information substantiating the basis.*

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation,   and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report

AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to *prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.*

Auxiliary Systems contain aluminum piping, piping components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air and outdoor air. A review of Turkey Point OE confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, all aluminum components exposed to uncontrolled indoor and outdoor air in the Auxiliary Systems are susceptible to cracking due to SCC and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and the External Surfaces Monitoring of Mechanical Components AMPs for components exposed to air internally or externally, respectively. The aluminum tanks included in the Auxiliary Systems are not part of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP and are managed using the External Surfaces Monitoring of Mechanical Components AMP for tanks exposed to air. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs are described in Appendix B.

3.3.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion *can occur due to halides present in the water that penetrates to the surface of the metal.*

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components, loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

The Auxiliary Systems includes both steel and stainless steel piping and tanks exposed to concrete. The concrete at Turkey Point is designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The stainless steel components are above groundwater and, therefore, do not require management as detailed above. A review of OE for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management.

Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks AMP is used to manage loss of material in steel piping exposed to concrete. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Buried and Underground Piping and Tanks AMP is described in Appendix B.

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.*

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.

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.*

Auxiliary Systems contain aluminum piping, piping components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air as well as outdoor air. A review of Turkey Point OE confirms halides are present in both the indoor and outdoor environments at Turkey Point. As such, all aluminum components exposed to uncontrolled indoor and outdoor air in the Auxiliary Systems are susceptible to loss of material and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material of these components will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and the External Surfaces Monitoring of Mechanical Components AMP for components exposed to air internally or externally, respectively. The aluminum tanks included in the Auxiliary Systems are not part of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP and are managed using the External Surfaces Monitoring of Mechanical Components AMP for tanks exposed to air. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs are described in Appendix B.

3.3.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Auxiliary Systems components:

- Section 4.3.2, Metal Fatigue of Piping Components

3.3.3 Conclusion

Auxiliary Systems piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for Auxiliary Systems components are identified in the summaries in Section 3.3.2 above.

A description of these AMPs is provided in Appendix B along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with Auxiliary Systems components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.3-1
Summary of Aging Management Evaluations for the Auxiliary Systems

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 001	Steel cranes: bridges, structural members, structural components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.7 "Other Plant-Specific TLAAs"	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. The Other Plant-Specific TLAAs (Section 4.7) are used to manage cumulative fatigue damage in steel cranes, bridges, structural members, and structural components exposed to any environment. This line item is used to evaluate structural items in Section 3.5. Further evaluation is documented in Section 3.3.2.2.1.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 002	Stainless steel, steel heat exchanger components and tubes, piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. The Metal Fatigue TLAA (Section 4.3.2) is used to manage cumulative fatigue damage in steel and stainless steel heat exchanger component and tubes, piping, and piping components exposed to any environment. Further evaluation is documented in Section 3.3.2.2.1.
3.3-1, 003	Stainless steel heat exchanger tubing, non-regenerative exposed to treated borated water >60°C (>140°F)	Cracking due to SCC; cyclic loading	AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Section 3.3.2.2.2)	Consistent with NUREG-2191. The Water Chemistry AMP is used to manage cracking of stainless steel in heat exchanger tubing exposed to treated borated water >60°C (>140°F). Further evaluation is documented in Section 3.3.2.2.2.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 003a	Stainless steel heat exchanger tubing, non-regenerative exposed to treated borated water >60°C (>140°F)	Cracking due to SCC; cyclic loading	AMP XI.M2, "Water Chemistry," and AMP XI.M21A, "Closed Treated Water Systems"	Yes (SRP-SLR Section 3.3.2.2.2)	Not used. Management of cracking in stainless steel heat exchanger tubing is addressed using a different line item (3.4-1, 011).

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 004	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191 for piping, piping components, and tanks. This line item is also applied to heat exchangers and filter housings. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs will be used to monitor cracking of stainless steel piping, piping components, heat exchanger components, and tanks exposed to air or condensation externally and internally, respectively. This line item is used for both Auxiliary Systems and Engineered Safety Features components. Further evaluation is documented in Section 3.3.2.2.3.
3.3-1, 005	There is no 3.3-1, 005 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 006	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191 for piping, piping components, and tanks. This line item is also applied to heat exchangers and filter housings. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs will be used to monitor external loss of material of stainless steel piping, piping components, heat exchanger components, and tanks exposed to air or condensation externally and internally, respectively. Further evaluation is documented in Section 3.3.2.2.4.
3.3-1, 007	Stainless steel high-pressure pump, casing exposed to treated borated water	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Not applicable. There are no stainless steel high-pressure pumps subject to cyclic loading associated with the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 008	Stainless steel heat exchanger components and tubes exposed to treated borated water >60°C (>140°F)	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Sections IWB, IWC, and IWD AMP is used to manage cracking of stainless steel heat exchanger components exposed to treated borated water >140°F. These components considered part of the reactor coolant and connected piping system.
3.3-1, 009	Steel, copper alloy (>15% Zn) external surfaces, piping, piping components exposed to air with borated water leakage	Loss of material due to Boric Acid Corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion AMP will be used to manage loss of material of steel surfaces exposed to air with borated water leakage.
3.3-1, 010	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There is no high-strength bolting associated with the Auxiliary Systems.
3.3-1, 011	There is no 3.3-1, 011 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 012	Steel; stainless steel, nickel alloy closure bolting exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP is used to manage loss of material in steel and stainless steel closure bolting exposed to outdoor air, uncontrolled indoor air or condensation.
3.3-1, 013	There is no 3.3-1, 013 in NUREG-2192.				
3.3-1, 014	There is no 3.3-1, 014 in NUREG-2192.				
3.3-1, 015	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP is used to manage loss of preload in metallic closure bolting exposed to any environment.
3.3-1, 016	This line item only applies to BWRs.				
3.3-1, 017	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry and One-Time Inspection AMPs are used to manage reduction of heat transfer in stainless steel heat exchanger tubes exposed to treated water or treated borated water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 used. Management of cracking in stainless steel piping, piping components, and tanks is addressed using a different line item (3.3-1, 020).
3.3-1, 019	This line item only applies to BWRs.				
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. The Water Chemistry and One-Time Inspection AMPs are used to manage cracking of stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water >60°C (>140°F) or treated borated water >60°C (>140°F)
3.3-1, 021	This line item only applies to BWRs.				
3.3-1, 022	This line item only applies to BWRs.				
3.3-1, 023	There is no 3.3-1, 023 in NUREG-2192.				
3.3-1, 024	There is no 3.3-1, 024 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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	Not applicable. There is no aluminum piping exposed to treated water or treated borated water in the Auxiliary Systems.
3.3-1, 026	This line item only applies to BWRs.				
3.3-1, 027	This line item only applies to BWRs.				
3.3-1, 028	Stainless steel piping, piping components, tanks exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not used. Management of cracking in stainless steel piping, piping components, and tanks is addressed using a different line item (3.3-1, 124).
3.3-1, 029	There is no 3.3-1, 029 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	Not applicable. There are no concrete components exposed to raw water within the scope of the Open-Cycle Cooling Water System AMP.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 030a	Fiberglass, HDPE piping, piping components exposed to raw water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There is no fiberglass piping or piping components exposed to raw water.
3.3-1, 031	There is no 3.3-1, 031 in NUREG-2192.				
3.3-1, 032	There is no 3.3-1, 032 in NUREG-2192.				
3.3-1, 032a	There is no 3.3-1, 0032a in NUREG-2192.				
3.3-1, 033	There is no 3.3-1, 033 in NUREG-2192.				
3.3-1, 034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System is used to manage loss of material and flow blockage in copper alloy piping exposed to raw water.
3.3-1, 035	There is no 3.3-1, 035 in NUREG-2192.				
3.3-1, 036	There is no 3.3-1, 036 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 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 is used to manage loss of material and flow blockage in steel piping and piping components exposed to raw water.
3.3-1, 038	Copper alloy, steel heat exchanger components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System AMP is used to manage loss of material and flow blockage in copper alloy heat exchanger components exposed to raw water.
3.3-1, 039	There is no 3.3-1, 039 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 040	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191 for piping and piping components. This line item has also been applied to heat exchanger components. The Open-Cycle Cooling Water System AMP is used to manage loss of material and flow blockage in stainless steel piping, piping components, and heat exchanger components exposed to raw water.
3.3-1, 041	There is no 3.3-1, 041 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 for copper heat exchanger tubes with raw water. The Open-Cycle Cooling Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are both used to manage copper heat exchanger tubes exposed to raw water. For copper heat exchanger tubes exposed to treated water, the Fire Water System AMP is used where the heat exchanger is associated with Fire Protection. There are no titanium heat exchanger tubes. Stainless steel heat exchanger tubes use a different item (3.3-1, 050).

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 043	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP is used to manage cracking of stainless steel piping and piping components exposed to treated water >60°C (>140°F).
3.3-1, 044	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no steel or stainless steel heat exchanger components exposed to closed-cycle cooling water (treated water) >60°C (>140°F) in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 045	Steel piping, piping components, tanks exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception for steel piping, piping components, and tanks exposed to closed-cycle cooling water (treated water). This line item has also been applied to heat exchanger components. The Closed Treated Water Systems AMP is used to manage the loss of material of steel piping, piping components, tanks, and heat exchanger components when exposed to treated water.
3.3-1, 046	Steel, copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP is used to manage loss of material in steel and copper alloy heat exchanger components, piping, and piping components exposed to closed-cycle cooling water (treated water).
3.3-1, 047	This line item only applies to BWRs.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 048	Aluminum piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no aluminum piping or piping components exposed to closed-cycle cooling water (treated water) in the Auxiliary Systems.
3.3-1, 049	Stainless steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception for stainless steel piping and piping components exposed to closed-cycle cooling water (treated water). This line item has also been applied to tanks and heat exchanger components. The Closed Treated Water Systems AMP is used to manage the loss of material of stainless steel piping, piping components, tanks, and heat exchanger components when exposed to treated water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 exception. The Closed Treated Water Systems AMP is used to manage reduction of heat transfer for stainless steel and copper heat exchanger tubes exposed to closed-cycle cooling water (treated water) >60°C (>140°F).
3.3-1, 051	Boraflex spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity due to boraflex degradation	AMP XI.M22, "Boraflex Monitoring"	No	Not applicable. There are no boraflex components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 052	Steel cranes: rails, bridges, structural members, structural components exposed to air	Loss of material due to general corrosion, wear, deformation, cracking	AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	No	Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is used to manage loss of material in steel cranes, bridges, structural members, and structural components exposed to any air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 053	There is no 3.3-1, 053 in NUREG-2192.				
3.3-1, 054	There is no 3.3-1, 054 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 AMP is used to manage loss of material in steel piping, piping components, and tanks exposed to condensation.
3.3-1, 056	There is no 3.3-1, 056 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 057	Elastomer fire barrier penetration seals exposed to air, condensation	Hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection AMP is used to manage hardening, loss of strength, and shrinkage of elastomer fire barriers exposed to air or condensation. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 058	Steel halon/carbon dioxide fire suppression system piping, piping components exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191 for steel piping and piping components. This line item is also applied to steel tanks in the Fire Protection system. The Fire Protection AMP is used to manage loss of material of steel fire suppression system piping, piping components, and tanks exposed to uncontrolled air or condensation.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 AMP is used to manage loss of material of steel fire rated doors exposed to air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 060	Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M26, "Fire Protection," and AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Fire Protection and Structures Monitoring AMPs are used to manage cracking or loss of material of reinforced concrete structural fire barriers. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 061	There is no 3.3-1, 061 in NUREG-2192.				
3.3-1, 062	There is no 3.3-1, 062 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. The Fire Water System AMP is used to manage loss of material and flow blockage of steel fire hydrants exposed to air or raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 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 for steel piping and piping components. This line item is also applied to steel heat exchanger components in the Fire Protection system. The Fire Water System AMP is used to manage loss of material and flow blockage of steel piping, piping components, and heat exchangers exposed to raw water or treated water.
3.3-1, 065	Aluminum piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no aluminum piping or piping components exposed to raw water or treated water in the Auxiliary Systems.
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. The Fire Water System AMP is used to manage loss of material and flow blockage in stainless steel piping and piping exposed to raw water.
3.3-1, 067	There is no 3.3-1, 067 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 068	There is no 3.3-1, 068 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 with exception for the Fuel Oil Chemistry AMP. The Fuel Oil Chemistry and One-Time Inspection AMPs are used to manage loss of material in copper alloy piping and piping components exposed to fuel oil.
3.3-1, 070	Steel piping, piping components, tanks exposed to fuel oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception for the Fuel Oil Chemistry AMP. The Fuel Oil Chemistry and One-Time Inspection AMPs are used to manage loss of material in steel piping, piping components, and tanks exposed to fuel oil. This line item is also used for structural items in Section 3.5.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 071	Stainless steel, aluminum piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception for the Fuel Oil Chemistry AMP. The Fuel Oil Chemistry and One-Time Inspection AMPs are used to manage loss of material in stainless steel piping and piping components exposed to fuel oil.
3.3-1, 072	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water, raw water (potable), waste water	Loss of material due to Selective Leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191 for all environments listed. This line item is also applied to gray cast iron heat exchanger components exposed to lubricating oil. The Selective Leaching AMP is used to manage loss of material of gray cast iron, copper alloy, and ductile iron piping, piping components, and heat exchanger components exposed to raw water, treated water, waste water, soil, and lubricating oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 073	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to air – outdoor	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There is no concrete or cementitious piping or piping components exposed to outdoor air in the Auxiliary Systems.
3.3-1, 074	There is no 3.3-1, 074 in NUREG-2192.				
3.3-1, 075	There is no 3.3-1, 075 in NUREG-2192.				
3.3-1, 076	Elastomer piping, piping components, ducting, ducting components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components is used to manage hardening or loss of strength of elastomer piping, piping components, ducting, ducting components, and seals exposed to air.
3.3-1, 077	There is no 3.3-1, 077 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 for components not associated with Fire Protection. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage loss of material for steel external surfaces exposed to uncontrolled air or condensation.
3.3-1, 079	There is no 3.3-1, 079 in NUREG-2192.				
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 AMP is used to manage loss of material for steel heat exchanger components, piping, and piping components exposed to uncontrolled air.
3.3-1, 081	There is no 3.3-1, 081 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 082	Elastomer, fiberglass piping, piping components, ducting, ducting components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material for elastomer piping, piping components, ducting, ducting components, and seals exposed to air.
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 AMP is used to manage cracking of stainless steel piping and piping components exposed to diesel engine exhaust.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 for piping and piping components. This line item is also applied to elastomer ducting. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage hardening or loss of strength due to elastomer degradation for elastomer piping, piping components, and ducting when exposed to indoor uncontrolled air, dry air, gas, raw water, or treated water.
3.3-1, 086	There is no 3.3-1, 086 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 is used to manage loss of material of steel and stainless steel piping and piping components exposed to diesel exhaust. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is also used to manage loss of material and flow blockage for steel components exposed to raw water.
3.3-1, 089	Steel piping, piping components exposed to condensation (internal)	Loss of material due to general, pitting, crevice corrosion	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no steel piping or piping components exposed to internal condensation that are associated with fire suppression and managed under the Fire Water System AMP.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 for ducting and ducting components. This line item is also applied to steel heat exchanger housings. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material in steel ducting, ducting components, and heat exchanger housings exposed to condensation.
3.3-1, 091	Steel piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is used to manage loss of material of steel piping and piping components exposed to waste water.
3.3-1, 092	There is no 3.3-1, 092 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 093	Copper alloy piping, piping components exposed to raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. Loss of material for copper alloy piping and piping components is addressed under other line items.
3.3-1, 094	Stainless steel ducting, ducting components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components are used to manage loss of material in stainless steel ducting and ducting components exposed to air externally or internally, respectively. Further evaluation is documented in Section 3.3.2.2.4.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 094a	Stainless steel ducting, ducting components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage cracking in stainless steel ducting and ducting components exposed to air externally or internally, respectively. Further evaluation is documented in Section 3.3.2.2.3.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 095	Copper alloy, stainless steel, nickel alloy piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage loss of material in copper and stainless steel piping or piping components exposed to waste water externally or internally, respectively.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 096	Elastomer piping, piping components, seals exposed to air, raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 for piping and piping components. This line item is also applied to elastomer ducting and elastomer piping with an internal environment of gas. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is used to manage loss of material of elastomer piping, piping components, and ducting exposed to uncontrolled air, dry air, gas, or raw water.
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 is used to manage reduction of heat transfer in aluminum and copper heat exchanger tubes exposed to air.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 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 for component, material, and aging mechanism. As the condensation environment is internal where this line item is applied, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material for steel heat exchanger components exposed to an internal environment of condensation.
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 for piping and piping components. This line item is also applied to steel tanks exposed to lubricating oil. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage loss of material in steel piping, piping components, and tanks exposed to lubricating oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 098	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage loss of material in steel heat exchanger components exposed to lubricating oil.
3.3-1, 099	Copper alloy, aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 for piping and piping components. This line item is also applied to heat exchanger components. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage loss of material of copper alloy piping, piping components, and heat exchanger components exposed to lubricating oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 and One-Time Inspection AMPs are used to manage loss of material in stainless steel piping and piping components exposed to lubricating oil.
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 components exposed to lubricating oil in the Auxiliary Systems.
3.3-1, 102	Boral®; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	AMP XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Consistent with NUREG-2191. The Monitoring of Neutron-Absorbing Materials other than Boraflex AMP is used to manage reduction of neutron-absorbing capacity, change in dimensions, and loss of material in boron carbine aluminum alloy exposed to treated borated water. This line item is used to evaluate structural items in Section 3.5.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 103	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to soil, concrete	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage cracking of concrete piping exposed to soil.
3.3-1, 104	High-density polyethylene (HDPE), fiberglass piping, piping components exposed to soil, concrete	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no HDPE or fiberglass piping or piping components in the Auxiliary Systems.
3.3-1, 105	There is no 3.3-1, 105 in NUREG-2192.				
3.3-1, 106	There is no 3.3-1, 106 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 AMP is used to manage loss of material in stainless steel piping exposed to soil and concrete.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 used. The stainless steel piping components exposed to soil, concrete, or underground are addressed using different line items. There are no titanium, copper alloy, nickel alloy, or super austenitic components exposed to soil, concrete, or underground in the Auxiliary Systems.
3.3-1, 109	Steel piping, piping components, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage loss of material in steel piping, piping components, and closure bolting exposed to soil or concrete.
3.3-1, 109a	There is no 3.3-1, 109a in NUREG-2192.				
3.3-1, 110	This line item only applies to BWRs.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 111	Steel structural steel exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP is used to manage loss of material structural steel exposed to indoor, uncontrolled air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 112	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Not used. A review of OE for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management. Further evaluation is documented in Section 3.3.2.2.9.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 113	Aluminum piping, piping components exposed to gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for aluminum piping and piping components exposed to gas.
3.3-1, 114	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191 for piping and piping components. This line item is also applied to heat exchanger tubes. There are no aging effects that require management for copper piping, piping components, and heat exchanger tubes exposed to gas or air.
3.3-1, 115	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no copper alloy piping or piping components exposed to air with borated water leakage in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for galvanized steel piping and piping components exposed to indoor uncontrolled air when there is not a potential for constant wetting of the surface.
3.3-1, 117	Glass piping elements exposed to air, lubricating oil, closed-cycle cooling water, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, underground	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for glass piping elements exposed to treated water.
3.3-1, 118	There is no 3.3-1, 118 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 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	Not applicable. There are no nickel alloy, PVC, or glass piping or piping components exposed to air with borated water leakage, indoor controlled air, condensation, waste water, or raw potable water in the Auxiliary Systems.
3.3-1, 120	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for stainless steel piping and piping components exposed to gas.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 121	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191 for piping and piping components. This line item is also applied to steel tanks exposed to gas as well as structural items exposed to indoor controlled air as described in Section 3.5. There are no aging effects that require management for steel piping, piping components, tanks, and structural items exposed to gas or indoor controlled air.
3.3-1, 122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 123	Titanium heat exchanger components other than tubes, piping and piping components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 124	Stainless steel, steel (with stainless steel or nickel alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water >60°C (>140°F), treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 for stainless steel piping, piping components, and spent fuel storage racks. This line item is also applied to the stainless steel spent fuel pool keyway gate, fuel assembly transfer components, and refueling pool liner. The Water Chemistry and One-Time Inspection AMPs are used to manage cracking of stainless steel piping, piping components, spent fuel storage racks, spent fuel pool keyway gate, fuel assembly transfer components, and refueling pool liner exposed to treated borated water >60°C (>140°F). This line item is also used to address structural items in Section 3.5. There are no steel with stainless steel cladding components exposed to treated water or treated borated water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 for stainless steel piping, piping components, and spent fuel storage racks. This line item is also applied to the stainless steel heat exchanger components, tanks, spent fuel pool keyway gate, spent fuel assembly handling tool, fuel transfer tube components, fuel assembly transfer components, refueling pool liner, and reactor cavity seal rings. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material of stainless steel piping, piping components, spent fuel storage racks, heat exchanger components, tanks, spent fuel pool keyway gate, spent fuel assembly handling tool, fuel transfer tube. components, fuel assembly transfer components, refueling pool liner, and reactor cavity seal rings exposed to treated borated water >60°C (>140°F). The structural items listed above are addressed in Section 3.5. There are no steel with stainless steel cladding components exposed to treated water or treated borated water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 for component type, material, environment, and aging event. The Fire Water System, Open-Cycle Cooling Water System, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are credited with managing wall thinning due to erosion of metallic components exposed to raw and waste water.
3.3-1, 127	Metallic piping, piping components, tanks exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.7)	Not applicable. OE shows no instances that meet the criteria of recurring internal corrosion. Further evaluation is documented in Section 3.3.2.2.7.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 128	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water	Loss of material due to general, pitting, crevice corrosion, MIC (soil, raw water only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material in steel tanks exposed to air, soil, or concrete.
3.3-1, 129	There is no 3.3-1, 129 in NUREG-2192.				
3.3-1, 130	Metallic sprinklers exposed to air, condensation, raw water, raw water (potable), treated water	Loss of material due to general (where applicable), pitting, crevice corrosion, MIC (except for aluminum, and in raw water, raw water (potable), treated water only); flow blockage due to fouling	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191. The Fire Water System AMP is used to manage loss of material and flow blockage in metallic sprinklers exposed to air or raw water.
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. The Fire Water System AMP is used to manage flow blockage

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material of steel and copper insulated piping, piping components, and tanks exposed to air or condensation.
3.3-1, 133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no HDPE underground piping or piping components included in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 134	Steel, stainless steel, copper alloy piping, piping components, and heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 for components with exposure to raw water internally. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs are used to manage loss of material in steel and stainless steel piping exposed to raw water internally or externally, respectively.
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 AMP is used to manage loss of material of stainless steel pump casings exposed to waste water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 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 for steel fire water storage tanks. This line item is also applied to fire water system piping exposed to an internal air environment. The Fire Water System AMP is used to manage loss of material in steel fire water storage tanks, piping, and piping components.
3.3-1, 137	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water, raw water, waste water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks that fall within the scope of Outdoor and Large Atmospheric Metallic Storage Tanks AMP that are exposed to treated water, raw water, or waste water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 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 for components not covered by NRC GL 89-13. This line item is also applied to any material with a coating that is within the scope of NRC GL 89-13. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is used to manage loss of coating or lining integrity for any material with a coating for piping, piping components, heat exchangers, and tanks exposed to treated water or raw water. For items within the scope of NRC GL 89-13, the Open-Cycle Cooling Water System AMP is used to manage the loss of coating or lining integrity.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 139	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	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 for components not covered by NRC GL 89-13. This line item is also applied to any material with a coating that is within the scope of NRC GL 89-13. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is used to manage loss of material for any material with a coating for piping, piping components, heat exchangers, and tanks exposed to treated water or raw water. For items within the scope of NRC GL 89-13, the Open-Cycle Cooling Water System AMP is used to manage the loss of material.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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	Not used. Any gray cast iron or ductile iron components with internal coatings have the coatings managed via Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP while the selective leaching of the base metal is addressed under the appropriate Selective Leaching AMP line item.
3.3-1, 141	There is no 3.3-1, 141 in NUREG-2192.				
3.3-1, 142	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to fuel oil, lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water and waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP is used to manage loss of material in stainless steel closure bolting exposed to raw water.
3.3-1, 143	There is no 3.3-1, 143 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 144	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage cracking in stainless steel piping exposed to concrete.
3.3-1, 145	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP is used to manage cracking of stainless steel closure bolts exposed to air.
3.3-1, 146	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Not used. The stainless steel underground piping in the Auxiliary Systems is managed using other line items.
3.3-1, 147	Nickel alloy, nickel alloy cladding piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no nickel alloy or nickel alloy clad piping or piping components exposed to closed-cycle cooling water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 148	There is no 3.3-1, 148 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 components in the Auxiliary Systems that require management.
3.3-1, 150	Fiberglass piping, piping components, ducting, ducting components exposed to air	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no fiberglass components in the Auxiliary Systems that require management.
3.3-1, 151	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not used. The aluminum and copper alloy heat exchanger tubes exposed to air in the Auxiliary Systems are managed using different line items.
3.3-1, 153	There is no 3.3-1, 153 in NUREG-2192.				
3.3-1, 154	There is no 3.3-1, 154 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. The Auxiliary Systems does not include any waste water >60°C (>140°F).
3.3-1, 156	There is no 3.3-1, 156 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 for piping and piping components. This line item is also applied to steel tanks, ducting, and ducting components exposed to outdoor air. The Fire Water System AMP is used to manage the loss of material in steel tanks, piping, and piping components that are associated with fire protection and are exposed to air. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material in steel piping, piping components, ducting, and ducting components that are not associated with fire protection and are exposed to air.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material in nickel alloy piping and piping components exposed to raw water.
3.3-1, 159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no fiberglass components in the Auxiliary Systems that require management.
3.3-1, 160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, raw water, waste water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. Cracking of copper alloys depends on the presence of ammonia or ammonia compound. A review of Turkey Point OE confirms that neither ammonia nor ammonia compounds are present.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 161	Copper alloy heat exchanger tubes exposed to condensation	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage reduction of heat transfer for copper alloy heat exchanger tubes exposed to condensation.
3.3-1, 162	There is no 3.3-1, 162 in NUREG-2192.				
3.3-1, 164	There is no 3.3-1, 164 in NUREG-2192.				
3.3-1, 165	There is no 3.3-1, 165 in NUREG-2192.				
3.3-1, 166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no copper components exposed to concrete in the Auxiliary Systems.
3.3-1, 167	Zinc piping components exposed to air-indoor controlled, air – indoor uncontrolled	None	None	No	Not applicable. There are no zinc components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 169	Steel, copper alloy piping, piping components exposed to steam	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no steel or copper piping or piping components exposed to steam in the Auxiliary Systems.
3.3-1, 170	Stainless steel piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not used. Stainless steel piping and piping components exposed to steam in the Auxiliary Systems are managed using different line items.
3.3-1, 171	There is no 3.3-1, 171 in NUREG-2192.				
3.3-1, 172	PVC piping, piping components exposed to air-outdoor	Reduction in impact strength due to photolysis	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no PVC piping or piping components in the Auxiliary Systems that require management.
3.3-1, 173	There is no 3.3-1, 173 in NUREG-2192.				
3.3-1, 174	There is no 3.3-1, 174 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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, or tanks in the Auxiliary Systems that require management.
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, or tanks in the Auxiliary Systems that require management.
3.3-1, 177	Fiberglass piping, piping components exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no fiberglass piping or piping components in the Auxiliary Systems that require management.
3.3-1, 178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not applicable. There are no fiberglass piping or piping components in the Auxiliary Systems that require management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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	Not used. Masonry walls and structural fire barriers are addressed with structural components.
3.3-1, 180	There is no 3.3-1, 180 in NUREG-2192.				
3.3-1, 181	Titanium piping, piping components exposed to condensation	None	None	No	Not applicable. There are no titanium piping or piping components in the Auxiliary Systems.
3.3-1, 182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There is no thermal insulation in the Auxiliary Systems that require management.
3.3-1, 184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no PVC piping, piping components, or tanks in the Auxiliary Systems that require management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 185	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no aluminum fire water storage tanks in the Auxiliary Systems.
3.3-1, 186	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no large or outdoor aluminum tanks in the Auxiliary Systems.
3.3-1, 187	There is no 3.3-1, 187 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 189	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191 for piping and piping components. This line item is also applied to ducting and ducting components. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage cracking of aluminum piping, piping components, ducting, and ducting components exposed to air or condensation externally or internally, respectively. Further evaluation is documented in Section 3.3.2.2.8.
3.3-1, 190	There is no 3.3-1, 190 in NUREG-2192.				
3.3-1, 191	There is no 3.3-1, 191 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 192	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no aluminum underground piping, piping components, or tanks in the Auxiliary Systems.
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 AMP will be used to manage long-term loss of material in steel components exposed to treated water, raw water, and waste water.
3.3-1, 194	PVC piping, piping components, and tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no PVC piping or piping components in the Auxiliary Systems that require management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 195	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no concrete or cementitious piping or piping components associated with fire protection that require aging management.
3.3-1, 196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no HDPE piping or piping components associated with fire protection that require aging management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 197	Metallic Fire Water System piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil, concrete	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not used. There are no Fire Water System piping, piping components, heat exchangers, or heat exchanger components that only have a leakage boundary (spatial) or structural integrity (attached) intended function that do not also have a pressure boundary function.
3.3-1, 198	Metallic Fire Water System piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC (all metallic materials except aluminum; in liquid environments only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. There are no Fire Water System piping, piping components, heat exchangers, or heat exchanger components that only have a leakage boundary (spatial) or structural integrity (attached) intended function that do not also have a pressure boundary function.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 199	Cranes: steel structural bolting exposed to air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	No	Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is used to manage loss of preload for steel structural bolting exposed to air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 200	There is no 3.3-1, 200 in NUREG-2192.				
3.3-1, 202	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Consistent with NUREG-2191. A review of Turkey Point OE confirms no degradation of concrete that would allow exposure of embedded portions of stainless steel piping or piping components to groundwater; there are no aging effects to manage. Further evaluation is documented in Section 3.3.2.2.9.
3.3-1, 203	This line item only applies to BWRs.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 204	There is no 3.3-1, 204 in NUREG-2192.				
3.3-1, 205	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage cracking of insulated stainless steel piping and piping components exposed to air. Further evaluation is documented in Section 3.3.2.2.3.
3.3-1, 206	There is no 3.3-1, 206 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	Not used. Stainless steel and copper alloy heat exchanger tubes exposed to raw water are managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP via another line item.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 208	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage cracking, loss of material, and flow blockage in concrete piping that is not covered by NRC GL 89-13.
3.3-1, 209	There is no 3.3-1, 209 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 or piping components in the Auxiliary Systems that require aging management.
3.3-1, 211	There is no 3.3-1, 211 in NUREG-2192.				
3.3-1, 212	There is no 3.3-1, 212 in NUREG-2192.				
3.3-1, 213	There is no 3.3-1, 213 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 piping or piping components exposed to soil in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 215	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no aluminum fire water storage tanks in the Auxiliary Systems.
3.3-1, 216	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no stainless steel fire water storage tanks in the Auxiliary Systems.
3.3-1, 217	There is no 3.3-1, 217 in NUREG-2192.				
3.3-1, 218	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion, MIC (water and soil environment only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no stainless steel fire water storage tanks in the Auxiliary Systems.
3.3-1, 219	Stainless steel piping, piping components exposed to steam	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not used. Stainless steel piping and piping components exposed to steam in the Auxiliary Systems are managed using different line items.
3.3-1, 220	There is no 3.3-1, 220 in NUREG-2192.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 221	There is no 3.3-1, 221 in NUREG-2192.				
3.3-1, 222	Stainless steel, nickel alloy tanks exposed to air, condensation (internal/external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material in stainless steel tanks exposed to condensation. Further evaluation is documented in Section 3.3.2.2.4.
3.3-1, 223	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no underground aluminum piping or piping components, or tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 224	There is no 3.3-1, 224 in NUREG-2192.				
3.3-1, 225	There is no 3.3-1, 225 in NUREG-2192.				
3.3-1, 226	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no underground aluminum piping or piping components, or tanks in the Auxiliary Systems.
3.3-1, 227	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not used. There are no large or outdoor aluminum tanks in the Auxiliary Systems. The aluminum tanks in the system are managed using different line items.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 228	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Not used. Stainless steel or nickel alloy tanks exposed to air or condensation in the Auxiliary Systems are managed using different line items.
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 exposed to soil or concrete in the 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 exposed to soil or concrete in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 231	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Not used. Stainless steel tanks exposed to air or condensation in the Auxiliary Systems are managed using different line items.
3.3-1, 232	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material in insulated stainless steel piping and piping components exposed to air or condensation. Further evaluation is documented in Section 3.3.2.2.4.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 233	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no insulated aluminum piping, piping components, or tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 234	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material in aluminum piping, piping components, and tanks exposed to air or condensation. Further evaluation is documented in Section 3.3.2.2.10.
3.3-1, 235	Metallic piping, piping components exposed to air-dry (internal)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M24, "Compressed Air Monitoring"	No	Consistent with NUREG-2191 for piping and piping components. This line item is also applied to metallic tanks exposed to dry air. The Compressed Air Monitoring AMP is used to manage loss of material in metallic piping, piping components, and tanks exposed to a dry air internal environment.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 236	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 237	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 238	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 239	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 240	Aluminum heat exchanger components exposed to waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no aluminum heat exchanger components exposed to waste water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 241	Stainless steel, nickel alloy heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage loss of material in stainless steel heat exchanger components exposed to air or condensation externally or internally, respectively. Further evaluation is documented in Section 3.3.2.2.4.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 242	Aluminum heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material in aluminum heat exchanger components exposed to air or condensation. Further evaluation is documented in Section 3.3.2.2.10.
3.3-1, 243	There is no 3.3-1, 243 in NUREG-2192.				
3.3-1, 244	This line item only applies to BWRs.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 245	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no insulated aluminum piping, piping components, or tanks in the Auxiliary Systems.
3.3-1, 246	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Not used. The stainless steel underground piping in the Auxiliary Systems is managed using other line items. There are no underground nickel alloy piping, piping, components, or tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 247	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no aluminum piping or piping components exposed to raw water or waste water in the Auxiliary Systems.
3.3-1, 248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not used. The environment and material combination do exist. However, this SLRA does not list combinations in the Table 2s that have no aging effects unless there is only one environment applicable to that component type and material.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 249	Steel heat exchanger tubes internal to components exposed to air-outdoor, air-indoor uncontrolled, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no internal steel heat exchanger components exposed to air or condensation in the Auxiliary Systems.
3.3-1, 250	Steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection AMP is used to manage loss of material in steel piping exposed to lubricating oil.
3.3-1, 251	There is no 3.3-1, 251 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 or piping components exposed to soil or concrete in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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	Not applicable. There are no PVC components in the Auxiliary Systems that require aging management.
3.3-1, 254	Aluminum heat exchanger components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage cracking in aluminum heat exchanger components exposed to air or condensation. Further evaluation is documented in Section 3.3.2.2.8.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 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 AMP is used to manage loss of material and cracking in fire damper assemblies.
3.3-1, 256	There is no 3.3-1, 256 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 and One-Time Inspection AMPs are used to manage reduction of heat transfer in copper alloy heat exchanger components exposed to lubricating oil.
3.3-1, 258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage flow blockage in steel, stainless steel, and copper alloy piping and piping components exposed to waste water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 259	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no aluminum piping or piping components exposed to raw water in the Auxiliary Systems.
3.3-1, 260	Metallic HVAC closure bolting exposed to air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components is used to manage loss of material and loss of preload of metallic HVAC closure bolting exposed to air or condensation.
3.3-1, 261	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water, raw water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 262	Titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 263	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no polymeric components in the Auxiliary Systems.

Table 3.3.2-1
Intake Cooling Water — Summary of Aging Management Evaluation

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-241	3.3-1, 109	A
Bolting	Pressure boundary	Carbon steel	Soil (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Raw water (ext)	Loss of material	Bolting Integrity	VII.I.A-423	3.3-1, 142	A
Bolting	Pressure boundary	Stainless steel	Raw water (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	Pressure boundary	Elastomer	Air – outdoor (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Expansion joint	Pressure boundary	Elastomer	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Expansion joint	Pressure boundary	Elastomer	Raw water (int)	Hardening or loss of strength Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.AP-75	3.3-1, 085	A
Flow element	Pressure boundary	Ductile iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Flow element	Pressure boundary	Ductile iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Flow element	Pressure boundary	Ductile iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Pressure boundary	Ductile iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-194	3.3-1, 037	A
Flow element	Pressure boundary	Ductile iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Flow element	Pressure boundary	Ductile iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.A-54	3.3-1, 040	A
Flow element	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Flow element	Throttle	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.A-54	3.3-1, 040	A
Flow element	Throttle	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Heat exchanger (Shell)	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-40	3.3-1, 080	A
Heat exchanger (Shell)	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-189	3.3-1, 046	B

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (Tubesheet)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Nozzle	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzle	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Nozzle	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Nozzle	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Nozzle	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Nozzle	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Nozzle	Pressure boundary	Nickel alloy	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Nozzle	Pressure boundary	Nickel alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-454	3.3-1, 158	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Orifice	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-198	3.3-1, 109	A
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Selective Leaching	VII.C1.A-02	3.3-1, 072	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Piping	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-194	3.3-1, 037	A
Piping	Pressure boundary	Coating	Raw water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VII.C1.A-416	3.3-1, 138	A
Piping	Pressure boundary	Concrete	Raw water (int)	Cracking Flow blockage Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-737	3.3-1, 208	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Concrete	Soil (ext)	Cracking	Buried and Underground Piping and Tanks	VII.I.AP-157	3.3-1, 103	A
Piping	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VIII.I.SP-6	3.4-1, 054	C
Piping	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Piping	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Ductile iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Ductile iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-194	3.3-1, 037	A
Piping	Pressure boundary	Ductile iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Piping	Pressure boundary	Ductile iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Ductile iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Nickel alloy	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Nickel alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-454	3.3-1, 158	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.A-54	3.3-1, 040	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-40	3.3-1, 080	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-189	3.3-1, 046	B
Piping and piping components	Structural integrity (attached)	Ductile iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Structural integrity (attached)	Ductile iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Ductile iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Piping and piping components	Structural integrity (attached)	Ductile iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Coating	Raw water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VII.C1.A-416	3.3-1, 138	A
Piping and piping components	Structural integrity (attached)	Coating	Raw water (int)	Loss of material	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VII.C1.A-414	3.3-1, 139	A
Pump casing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Pump casing	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Pump casing	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.A-727	3.3-1, 134	E, 2
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (ext)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (ext)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Pump casing	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Strainer body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Strainer body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-194	3.3-1, 037	A
Strainer body	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Strainer body	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Strainer body	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Strainer body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Strainer body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Strainer body	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Strainer element	Filter	Stainless steel	Raw water (ext)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.A-54	3.3-1, 040	A
Thermowell	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Thermowell	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Tubing	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Tubing	Pressure boundary	Nickel alloy	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Nickel alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-454	3.3-1, 158	A
Tubing	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Tubing	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.A-54	3.3-1, 040	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-194	3.3-1, 037	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VIII.I.SP-6	3.4-1, 054	C
Valve body	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Valve body	Pressure boundary	Copper alloy >8% Al	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy >8% Al	Air – outdoor (ext)	None	None	VIII.I.SP-6	3.4-1, 054	C
Valve body	Pressure boundary	Copper alloy >8% Al	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-196	3.3-1, 034	A
Valve body	Pressure boundary	Copper alloy >8% Al	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-47	3.3-1, 072	A
Valve body	Pressure boundary	Ductile iron	Raw water (int)	Wall thinning	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Ductile iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Ductile iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A
Valve body	Pressure boundary	Ductile iron	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-51	3.3-1, 072	A
Valve body	Pressure boundary	Ductile iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.C1.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Nickel alloy	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Nickel alloy	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Nickel alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-454	3.3-1, 158	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Open-Cycle Cooling Water System	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-1: Intake Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-727	3.3-1, 134	A

Notes for Table 3.3.2-1

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.3.2-1

1. The Open-Cycle Cooling Water System AMP is enhanced to manage the wall thinning due to erosion aging effect.
2. These pump casings have a raw water external environment and loss of material is managed by the External Surfaces Monitoring of Mechanical Components AMP.

Table 3.3.2-2
Component Cooling Water — Summary of Aging Management Evaluation

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Accumulator	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Accumulator	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Accumulator	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Condensation (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Condensation (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Filter element	Filter	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Filter housing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Flow element	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Heat exchanger	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-40	3.3-1, 080	A
Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	C
Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	C
Heat exchanger	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	C

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	C
Heat exchanger	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-40	3.3-1, 080	A
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Heat exchanger (channel head)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-179	3.3-1, 038	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-40	3.3-1, 080	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-189	3.3-1, 046	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.C2.AP-133	3.3-1, 099	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.AP-199	3.3-1, 046	D
Heat exchanger (tubes)	Pressure boundary	Copper alloy >8% Al	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.C2.AP-133	3.3-1, 099	C
Heat exchanger (tubes)	Heat transfer	Copper alloy >8% Al	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System	VII.C1.AP-187	3.3-1, 042	A
Heat exchanger (tubes)	Heat transfer	Copper alloy >8% Al	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems	VII.C2.AP-205	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy >8% Al	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-179	3.3-1, 038	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Copper alloy >8% Al	Raw water (int)	Loss of material	Selective Leaching	VII.C1.A-66	3.3-1, 072	A
Heat exchanger (tubes)	Pressure boundary	Copper alloy >8% Al	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.AP-199	3.3-1, 046	D
Heat exchanger (tubes)	Pressure boundary	Copper alloy >8% Al	Treated water (ext)	Loss of material	Selective Leaching	VII.C2.AP-43	3.3-1, 072	C
Heat exchanger (tubesheet)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.C2.AP-127	3.3-1, 097	A
Heat exchanger (tubesheet)	Pressure boundary	Carbon steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.AP-189	3.3-1, 046	B
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System	VII.C1.AP-179	3.3-1, 038	A
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.AP-199	3.3-1, 046	D
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Orifice	Throttle	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Orifice	Throttle	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.A-26	3.3-1, 055	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.A-26	3.3-1, 055	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Pump casing	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Pump casing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Pump casing	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Pump casing	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Pump casing	Pressure boundary	Gray cast iron	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Pump casing	Pressure boundary	Gray cast iron	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Pump casing	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching	VII.C2.A-50	3.3-1, 072	A
Tank	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tank	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tank	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.A-26	3.3-1, 055	A
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	C

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	C
Tank	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	C
Tank	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	C
Tank	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C2.AP-221c	3.3-1, 006	C
Tank	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Thermowell	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tubing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Tubing	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Tubing	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tubing	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.A-26	3.3-1, 055	A
Tubing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C2.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C2.AP-209c	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Valve body	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Valve body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.A-26	3.3-1, 055	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Condensation (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-199	3.3-1, 046	B
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-199	3.3-1, 046	B
Valve body	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	VII.C2.AP-32	3.3-1, 072	A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A

Table 3.3.2-2: Component Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C2.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C2.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B

Notes for Table 3.3.2-2

A. fConsistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-3
Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Filter housing	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Filter housing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Filter housing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter housing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	C

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.A3.AP-189	3.3-1, 046	B
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	VII.A3.A-101	3.3-1, 017	A
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems	VII.C2.AP-188	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	C

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Pump casing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	C

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-751c	3.3-1, 222	A
Tank	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	C
Thermowell	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Tubing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Tubing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Tubing	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-3: Spent Fuel Pool Cooling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Vortex diffuser	Direct flow	Stainless steel	Treated borated water (ext)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Vortex diffuser	Direct flow	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A

Notes for Table 3.3.2-3

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-4
Chemical and Volume Control — Summary of Aging Management Evaluation

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Filter (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Filter (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Filter	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Flow element (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Flow element (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Flow element (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Flow element (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Flow element	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Flow element	Throttle	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Heat exchanger (channel head)	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Heat exchanger (channel head)	Pressure boundary	Gray cast iron	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Heat exchanger (channel head)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching	VII.E1.AP-31	3.3-1, 072	C
Heat exchanger (channel head)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.E1.AP-189	3.3-1, 046	B
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	C

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	C
Heat exchanger (channel head)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.AP-118	3.3-1, 020	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.A3.AP-189	3.3-1, 046	B
Heat exchanger (shell)	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (shell)	Pressure boundary	Copper alloy >15% Zn	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.E1.AP-133	3.3-1, 099	C
Heat exchanger (tubes)	Heat transfer	Copper alloy	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis One-Time Inspection	VII.E1.A-791	3.3-1, 257	A
Heat exchanger (tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.F1.AP-205	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.E1.AP-133	3.3-1, 099	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.E1.AP-199	3.3-1, 046	D

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	VII.E1.A-101	3.3-1, 017	A, 1
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems	VII.E4.AP-188	3.3-1, 050	B, 1
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry	VII.E1.A-69	3.3-1, 003	A
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.E1.AP-133	3.3-1, 099	C
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	VII.E1.AP-65	3.3-1, 072	A
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.E1.AP-199	3.3-1, 046	D

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	C
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.AP-118	3.3-1, 020	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Orifice	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Piping	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Piping	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Pressure boundary	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Pump casing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Tank	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.I.A-751d	3.3-1, 222	A, 2
Tank	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	C
Tank	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	C

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Thermowell	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Thermowell	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Tubing (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E1.AP-221c	3.3-1, 006	A, 2
Tubing	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.E1.AP-138	3.3-1, 100	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Tubing	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Condensation (int)	None	None	VII.J.AP-144	3.3-1, 114	A, 2
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E1.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Valve body	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.E1.AP-138	3.3-1, 100	A

Table 3.3.2-4: Chemical and Volume Control — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Valve body	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A

Notes for Table 3.3.2-4

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes for Table 3.3.2-4

1. Seal water heat exchangers do not have a heat transfer function but support component cooling water system pressure boundary and CVCS structural integrity.
2. Wetted gas in the gas space and vent lines of the volume control tanks to account for moisture.

Table 3.3.2-5
Primary Water Makeup — Summary of Aging Management Evaluation

Table 3.3.2-5: Primary Water Makeup — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-5: Primary Water Makeup — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A

Table 3.3.2-5: Primary Water Makeup — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-5: Primary Water Makeup — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-5: Primary Water Makeup — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A

Notes for Table 3.3.2-5

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.3.2-6
Primary Sampling — Summary of Aging Management Evaluation

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Heat exchanger (shell and cover)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (shell and cover)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Heat exchanger (shell and cover)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.E1.AP-189	3.3-1, 046	B
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Piping and piping components	Pressure boundary	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Piping	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water > 140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Tubing (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Tubing (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E1.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Tubing	Leakage boundary (spatial)	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E1.AP-221c	3.3-1, 006	A
Tubing (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Tubing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Tubing (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Tubing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tubing	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Tubing	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E1.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Valve body	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-209b	3.3-1, 004	A
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E1.AP-221b	3.3-1, 006	A
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A

Table 3.3.2-6: Primary Sampling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E1.AP-221c	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.E1.AP-79	3.3-1, 125	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VII.E1.A-103	3.3-1, 124	A

<u>Notes for Table 3.3.2-6</u>

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-7
Secondary Sampling — Summary of Aging Management Evaluation

Table 3.3.2-7: Secondary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VIII.H.S-421	3.4-1, 073	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Heat exchanger (shell)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-127b	3.4-1, 003	C

Table 3.3.2-7: Secondary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VIII.F.S-25	3.4-1, 026	B
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VIII.F.S-25	3.4-1, 026	B
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-88	3.4-1, 011	C
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A

Table 3.3.2-7: Secondary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Pressure boundary	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components	Pressure boundary	Stainless steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.F.SP-74	3.4-1, 014	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-127b	3.4-1, 003	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-118b	3.4-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-88	3.4-1, 011	A

Table 3.3.2-7: Secondary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-127b	3.4-1, 003	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-118b	3.4-1, 002	A
Tubing	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	A
Tubing	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	A
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Tubing	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-88	3.4-1, 011	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.F.SP-74	3.4-1, 014	A

Table 3.3.2-7: Secondary Sampling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	A
Valve body	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-87	3.4-1, 085	A
Valve body	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-88	3.4-1, 011	A

Notes for Table 3.3.2-7

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.3.2-8
Waste Disposal — Summary of Aging Management Evaluation

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Drain	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Drain	Pressure boundary	Gray cast iron	Concrete	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-198	3.3-1, 109	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Drain	Pressure boundary	Gray cast iron	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Drain	Pressure boundary	Gray cast iron	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-281	3.3-1, 091	A
Drain	Pressure boundary	Gray cast iron	Waste water (int)	Loss of material	Selective Leaching	VII.E5.A-547	3.3-1, 072	A
Drain	Pressure boundary	Gray cast iron	Waste water (int)	Long-term loss of material	One-Time Inspection	VII.E5.A-785	3.3-1, 193	A
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-189	3.3-1, 046	B

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.AP-199	3.3-1, 046	D
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Selective Leaching	VII.C2.AP-32	3.3-1, 072	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-199	3.3-1, 046	D
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	VII.C2.AP-32	3.3-1, 072	C
Heat exchanger (tubesheet)	Pressure boundary	Carbon steel	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.C2.AP-189	3.3-1, 046	B
Heat exchanger (tubesheet)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.AP-189	3.3-1, 046	B
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Concrete	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A
Piping	Leakage boundary (spatial)	Stainless steel	Concrete	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-137	3.3-1, 107	A
Piping	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-26	3.3-1, 055	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Concrete	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A
Piping	Pressure boundary	Stainless steel	Concrete	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-137	3.3-1, 107	A
Piping	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A2.AP-79	3.3-1, 125	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Piping	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Stainless steel	Waste water (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E5.A-411	3.3-1, 135	C
Piping	Pressure boundary	Stainless steel	Waste water (int)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-780	3.3-1, 258	A
Piping	Pressure boundary	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection	VII.E5.A-785	3.3-1, 193	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-281	3.3-1, 091	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Structural integrity (attached)	Stainless steel	Concrete	Cracking	Buried and Underground Piping and Tanks	VII.I.A-425	3.3-1, 144	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Concrete	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-137	3.3-1, 107	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-278	3.3-1, 095	A
Pump casing	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Pump casing	Pressure boundary	Stainless steel	Waste water (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E5.A-411	3.3-1, 135	A
Pump casing	Pressure boundary	Stainless steel	Waste water (int)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-780	3.3-1, 258	A
Pump casing	Pressure boundary	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-278	3.3-1, 095	A
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Tubing	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Tubing	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-26	3.3-1, 055	A
Tubing	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Waste water (int)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-780	3.3-1, 258	A
Tubing	Pressure boundary	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-278	3.3-1, 095	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Valve body	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-26	3.3-1, 055	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Waste water (ext)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy	Waste water (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.E5.AP-272	3.3-1, 095	E, 2
Valve body	Pressure boundary	Copper alloy	Waste water (int)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-780	3.3-1, 258	A
Valve body	Pressure boundary	Copper alloy	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-272	3.3-1, 095	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.C1.AP-221b	3.3-1, 006	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	VII.A3.AP-79	3.3-1, 125	A

Table 3.3.2-8: Waste Disposal — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Stainless steel	Waste water (int)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.A-780	3.3-1, 258	A
Valve body	Pressure boundary	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-278	3.3-1, 095	A

Notes for Table 3.3.2-8

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.3.2-8

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is enhanced to manage the wall thinning due to erosion aging effect.
2. The external surface of these valves can be submerged in water. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage the loss of material aging effect for the external surface of these valves.

Table 3.3.2-9
Plant Air — Summary of Aging Management Evaluation

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	C
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	C
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	C
Accumulator	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	C
Accumulator	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	C
Accumulator	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	C

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Accumulator	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	C
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Condensation (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Condensation (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Dryer	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.A-451b	3.3-1, 189	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Dryer	Pressure boundary	Aluminum	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F2.A-763b	3.3-1, 234	A
Dryer	Pressure boundary	Aluminum	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.A-451c	3.3-1, 189	A
Dryer	Pressure boundary	Aluminum	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-763c	3.3-1, 234	A
Dryer	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Dryer	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Dryer	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Dryer	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Filter housing	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Filter housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Filter housing	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E1.A-722	3.3-1, 157	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter housing	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Filter housing	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.A-26	3.3-1, 055	A
Filter housing	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Filter housing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Filter housing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter housing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Filter housing	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Filter housing	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter housing	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Filter housing	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Flex hose	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Flex hose	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flex hose	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Flex hose	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	C
Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	C
Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	C
Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	C
Orifice	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.A-722	3.3-1, 157	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-198	3.3-1, 109	A
Piping	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping	Pressure boundary	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-137	3.3-1, 107	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Rupture disc	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Rupture disc	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Rupture disc	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Strainer body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Strainer body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Strainer body	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Thermowell	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Copper alloy	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy	Condensation (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Valve body	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F2.A-763b	3.3-1, 234	A
Valve body	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.A-451b	3.3-1, 189	A
Valve body	Pressure boundary	Aluminum	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F2.A-763b	3.3-1, 234	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.A-451b	3.3-1, 189	A
Valve body	Pressure boundary	Aluminum	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.A-451c	3.3-1, 189	A
Valve body	Pressure boundary	Aluminum	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-763c	3.3-1, 234	A
Valve body	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.A-722	3.3-1, 157	A
Valve body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Valve body	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Valve body	Pressure boundary	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.D.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.D.AP-221b	3.3-1, 006	A

Table 3.3.2-9: Plant Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.D.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A

Notes for Table 3.3.2-9

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.3.2-10
Normal Containment Ventilation — Summary of Aging Management Evaluation

Table 3.3.2-10: Normal Containment Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F3.A-794	3.3-1, 260	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-10: Normal Containment Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F3.A-794	3.3-1, 260	A
Duct	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Duct	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Duct	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F3.A-504	3.3-1, 085	C
Duct	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F3.AP-103	3.3-1, 096	C

Table 3.3.2-10: Normal Containment Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Duct	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Fan housing	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A

Table 3.3.2-10: Normal Containment Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F3.A-417	3.3-1, 096b	E, 1
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Condensation (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F3.A-565	3.3-1, 161	A
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.F3.AP-205	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F3.AP-203	3.3-1, 046	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	VII.F3.AP-65	3.3-1, 072	A

Table 3.3.2-10: Normal Containment Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F3.AP-209c	3.3-1, 004	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F3.A-770c	3.3-1, 241	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VIII.E.S-25	3.4-1, 026	B
Valve body	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A

Notes for Table 3.3.2-10

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.3.2-10

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material for the interior surface of this heat exchanger shell.

Table 3.3.2-11
Auxiliary Building and Electrical Equipment Room Ventilation —
Summary of Aging Management Evaluation

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F2.A-794	3.3-1, 260	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
HVAC Closure Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F2.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
HVAC Closure Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F2.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Cooler housing	Pressure boundary	Galvanized steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Cooler housing	Pressure boundary	Galvanized steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-08	3.3-1, 090	A
Damper housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Damper housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Duct	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Duct	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Duct	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Duct	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Duct	Pressure boundary	Galvanized steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-722	3.3-1, 157	C

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Fan housing	Pressure boundary	Galvanized steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-722	3.3-1, 157	C
Fan housing	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Flex connection	Pressure boundary	Elastomer	Air – indoor controlled (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.A-504	3.3-1, 085	A
Flex connection	Pressure boundary	Elastomer	Air – indoor controlled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Flex connection	Pressure boundary	Elastomer	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Heat exchanger (tubes)	Leakage boundary (spatial)	Stainless steel	Condensation (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-770c	3.3-1, 241	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Leakage boundary (spatial)	Stainless steel	Condensation (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	C
Heat exchanger (tubes)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-221c	3.3-1, 006	A

Table 3.3.2-11: Auxiliary Building and Electrical Equipment Room Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.AP-209c	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A

<u>Notes for Table 3.3.2-11</u>

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-12
Control Building Ventilation —
Summary of Aging Management Evaluation

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F1.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F1.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F1.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor controlled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Galvanized steel	Air – indoor controlled (ext)	Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F1.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
HVAC Closure Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F1.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F1.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Damper housing	Pressure boundary	Galvanized steel	Air – indoor controlled (ext)	None	None	V.F.EP-14	3.2-1, 059	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Damper housing	Pressure boundary	Galvanized steel	Air – indoor controlled (int)	None	None	V.F.EP-14	3.2-1, 059	A
Damper housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Damper housing	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-99b	3.3-1, 094	A
Damper housing	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.A-781b	3.3-1, 094a	A
Damper housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.A-781c	3.3-1, 094a	A
Damper housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.AP-99c	3.3-1, 094	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Duct	Pressure boundary	Galvanized steel	Air – indoor controlled (ext)	None	None	V.F.EP-14	3.2-1, 059	A
Duct	Pressure boundary	Galvanized steel	Air – indoor controlled (int)	None	None	V.F.EP-14	3.2-1, 059	A
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Fan housing	Pressure boundary	Galvanized steel	Air – indoor controlled (ext)	None	None	V.F.EP-14	3.2-1, 059	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor controlled (int)	None	None	V.F.EP-14	3.2-1, 059	A
Fan housing	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Fan housing	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-99b	3.3-1, 094	A
Fan housing	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.A-781b	3.3-1, 094a	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fan housing	Pressure boundary	Stainless steel	Air – indoor controlled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.A-781c	3.3-1, 094a	A
Fan housing	Pressure boundary	Stainless steel	Air – indoor controlled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.AP-99c	3.3-1, 094	A
Filter housing	Pressure boundary	Galvanized steel	Air – indoor controlled (ext)	None	None	V.F.EP-14	3.2-1, 059	A
Filter housing	Pressure boundary	Galvanized steel	Air – indoor controlled (int)	None	None	V.F.EP-14	3.2-1, 059	A
Flex connection	Pressure boundary	Elastomer	Air – indoor controlled (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.A-504	3.3-1, 085	A
Flex connection	Pressure boundary	Elastomer	Air – indoor controlled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flex connection	Pressure boundary	Elastomer	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-788c	3.3-1, 254	A
Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-771c	3.3-1, 242	A
Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.A-419	3.3-1, 096a	A
Heat exchanger (tubes)	Heat transfer	Copper alloy	Air – indoor controlled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.A-419	3.3-1, 096a	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.F2.AP-205	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Air – indoor controlled (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-199	3.3-1, 046	D
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Treated water (ext)	Loss of material	Closed Treated Water Systems	VII.F2.AP-199	3.3-1, 046	D
Heat exchanger (header)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (header)	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	C
Heat exchanger (header)	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-209b	3.3-1, 004	C

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-189	3.3-1, 046	B
Heat exchanger (shell) (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (water box)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (water box)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-189	3.3-1, 046	B
Orifice (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Orifice	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Orifice	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Orifice	Throttle	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Piping (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-202	3.3-1, 045	B
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Piping	Pressure boundary	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-137	3.3-1, 107	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Pump casing (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-202	3.3-1, 045	B
Strainer body (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Strainer body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-202	3.3-1, 045	B
Strainer element	Filter	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-202	3.3-1, 045	B
Tank (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-202	3.3-1, 045	B

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Tubing (insulated)	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-761c	3.3-1, 232	A
Tubing (insulated)	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.I.A-734c	3.3-1, 205	A
Valve body (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-12: Control Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A

Notes for Table 3.3.2-12

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-13
Emergency Diesel Generator Building Ventilation —
Summary of Aging Management Evaluation

Table 3.3.2-13: Emergency Diesel Generator Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F4.A-794	3.3-1, 260	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
HVAC Closure Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F4.A-794	3.3-1, 260	A

Table 3.3.2-13: Emergency Diesel Generator Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
HVAC Closure Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F4.A-794	3.3-1, 260	A
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C

Table 3.3.2-13: Emergency Diesel Generator Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Filter housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C

Notes for Table 3.3.2-13

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.3.2-14
Turbine Building Ventilation — Summary of Aging Management Evaluation

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Fan housing	Pressure boundary	Galvanized steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-08	3.3-1, 090	A

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter	Filter	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Filter	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter	Pressure boundary	Galvanized steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Flex hose	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A
Flex hose	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A
Flex hose	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (housing)	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-08	3.3-1, 090	A
Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-788c	3.3-1, 254	A
Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-771c	3.3-1, 242	A
Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-419	3.3-1, 096a	A

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Heat transfer	Copper alloy	Air – indoor controlled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F2.A-419	3.3-1, 096a	A
Heat exchanger (tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.F2.AP-205	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Air – indoor controlled (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-199	3.3-1, 046	D
Heat exchanger (water box)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (water box)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-189	3.3-1, 046	B
HVAC closure bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F4.A-794	3.3-1, 260	A

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
HVAC closure bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F4.A-794	3.3-1, 260	A
HVAC closure bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Cracking Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components	VII.F4.A-794	3.3-1, 260	A
Orifice (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Orifice	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Orifice	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Throttle	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Piping (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-202	3.3-1, 045	B
Pump casing (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Sight glass	Pressure boundary	Glass	Treated water (int)	None	None	VII.J.AP-166	3.3-1, 117	A
Sight glass	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-209b	3.3-1, 004	A

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Sight glass	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F1.AP-221b	3.3-1, 006	A
Sight glass	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Tank (insulated)	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	D
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F2.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.F1.AP-199	3.3-1, 046	B
Valve body	Pressure boundary	Copper alloy	Condensation (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-14: Turbine Building Ventilation — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.F2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B

Notes for Table 3.3.2-14

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-15
Fire Protection — Summary of Aging Management Evaluation

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Damper housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.A-451b	3.3-1, 189	C
Damper housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-451c	3.3-1, 189	C
Damper housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	Loss of material	Fire Protection	VII.G.A-789	3.3-1, 255	A
Damper housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	Fire Protection	VII.G.A-789	3.3-1, 255	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Damper housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	C
Damper housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	C
Damper housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-209c	3.3-1, 004	C
Damper housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-221c	3.3-1, 006	C
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	Pressure boundary	Elastomer	Raw water (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-75	3.3-1, 085	A
Expansion joint	Pressure boundary	Elastomer	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-76	3.3-1, 096	A
Filter housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.G.AP-234	3.3-1, 070	B
Flame arrestor	Fire prevention	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Flame arrestor	Fire prevention	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F1.A-722	3.3-1, 157	C

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flexible hose	Pressure boundary	Elastomer	Air – outdoor (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Flexible hose	Pressure boundary	Elastomer	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Flexible hose	Pressure boundary	Elastomer	Gas (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-729	3.3-1, 085	A
Flexible hose	Pressure boundary	Elastomer	Gas (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	-	-	I, 2
Flexible hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A
Flexible hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.G.AP-138	3.3-1, 100	A
Flexible hose	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-55	3.3-1, 066	A
Flexible hose	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (channel head)	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (channel head)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.AP-197	3.3-1, 064	C
Heat exchanger (channel head)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-47	3.3-1, 072	C
Heat exchanger (channel head)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Fire Water System	VII.G.A-33	3.3-1, 064	C
Heat exchanger (shell)	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Heat exchanger (shell)	Pressure boundary	Gray cast iron	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-131	3.3-1, 098	A
Heat exchanger (shell)	Pressure boundary	Gray cast iron	Lubricating oil (int)	Loss of material	Selective Leaching	-	-	H, 3
Heat exchanger (shell)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	C
Heat exchanger (shell)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching	VII.G.A-51	3.3-1, 072	C
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis One-Time Inspection	VII.G.A-791	3.3-1, 257	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Raw water (int)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-187	3.3-1, 042	A
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Treated water (ext)	Reduction of heat transfer	Fire Water System	VII.G.AP-187	3.3-1, 042	E
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.G.AP-133	3.3-1, 099	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.AP-197	3.3-1, 064	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-47	3.3-1, 072	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Fire Water System	VII.G.AP-197	3.3-1, 064	C

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Selective Leaching	VII.F4.AP-43	3.3-1, 072	C
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.G.AP-133	3.3-1, 099	C
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material	Fire Water System	VII.G.AP-197	3.3-1, 064	C
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-47	3.3-1, 072	C
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material Flow blockage	Fire Water System	VII.G.AP-197	3.3-1, 064	C
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material	Selective Leaching	VII.F4.AP-43	3.3-1, 072	C
Fire hydrant	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	Fire Water System	VII.G.AP-149	3.3-1, 063	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Fire hydrant	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Fire hydrant	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.AP-149	3.3-1, 063	A
Fire hydrant	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-51	3.3-1, 072	A
Fire hydrant	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Fire hydrant	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-198	3.3-1, 109	A
Nozzle	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.A-451b	3.3-1, 189	A
Nozzle	Pressure boundary	Aluminum	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-451c	3.3-1, 189	A
Nozzle	Pressure boundary	Aluminum	Air – indoor uncontrolled (int)	Flow blockage	Fire Water System	VII.G.A-404	3.3-1, 131	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-403	3.3-1, 130	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-47	3.3-1, 072	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Nozzle	Spray	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.A-451b	3.3-1, 189	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzle	Spray	Aluminum	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-451c	3.3-1, 189	A
Nozzle	Spray	Aluminum	Air – indoor uncontrolled (int)	Flow blockage	Fire Water System	VII.G.A-404	3.3-1, 131	A
Nozzle	Spray	Copper alloy >15% Zn	Air – indoor uncontrolled (int)	Flow blockage	Fire Water System	VII.G.A-404	3.3-1, 131	A
Nozzle	Spray	Copper alloy >15% Zn	Air – outdoor (int)	Flow blockage	Fire Water System	VII.G.A-404	3.3-1, 131	A
Nozzle	Spray	Copper alloy >15% Zn	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	Spray	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	Spray	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Nozzle	Spray	Copper alloy >15% Zn	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Nozzle	Spray	Copper alloy >15% Zn	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-403	3.3-1, 130	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzle	Spray	Copper alloy >15% Zn	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-47	3.3-1, 072	A
Nozzle	Spray	Copper alloy >15% Zn	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-55	3.3-1, 066	A
Orifice	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Fire Water System	VII.G.A-412	3.3-1, 136	C
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.G.AP-234	3.3-1, 070	B
Piping	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.G.AP-127	3.3-1, 097	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-198	3.3-1, 109	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Galvanized steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Piping	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Pressure boundary	Galvanized steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping	Pressure boundary	Galvanized steel	Lubricating oil (int)	Loss of material	One-Time Inspection	VII.G.AP-117	3.3-1, 250	A
Piping	Pressure boundary	Galvanized steel	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Piping	Pressure boundary	Galvanized steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	A
Piping	Pressure boundary	Galvanized steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Gray cast iron	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Gray cast iron	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-51	3.3-1, 072	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-198	3.3-1, 109	A
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Selective Leaching	VII.G.A-02	3.3-1, 072	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-55	3.3-1, 066	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-51	3.3-1, 072	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
RCP Oil Collection Drip Pans and Enclosures	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	C
RCP Oil Collection Drip Pans and Enclosures	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	C
RCP Oil Collection Drip Pans and Enclosures	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-209c	3.3-1, 004	C

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
RCP Oil Collection Drip Pans and Enclosures	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-221c	3.3-1, 006	C
RCP Oil Collection Drip Pans and Enclosures	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.G.AP-138	3.3-1, 100	A
Strainer body	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Strainer body	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Strainer body	Pressure boundary	Gray cast iron	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Strainer body	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Strainer body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	A
Strainer body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-51	3.3-1, 072	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer body	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Strainer element	Filter	Stainless steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-55	3.3-1, 066	A
Tank	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Fire Protection	VII.G.AP-150	3.3-1, 058	C
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Fire Water System	VII.G.A-722	3.3-1, 157	C
Tank	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Fire Water System	VII.G.A-722	3.3-1, 157	C
Tank	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Tank	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry	VII.G.AP-234a	3.3-1, 070	B
Tank	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	C
Tank	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-131	3.3-1, 098	C
Tank	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	Fire Water System	VII.G.A-412	3.3-1, 136	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.G.AP-132	3.3-1, 069	B
Tubing	Pressure boundary	Copper alloy >15% Zn	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.G.AP-133	3.3-1, 099	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.AP-197	3.3-1, 064	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-47	3.3-1, 072	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.G.AP-136a	3.3-1, 071	B
Tubing	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Tubing	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-55	3.3-1, 066	A
Tubing	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.A-451b	3.3-1, 189	A
Valve body	Pressure boundary	Aluminum	Gas (int)	None	None	VII.J.AP-37	3.3-1, 113	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Fire Protection	VII.G.AP-150	3.3-1, 058	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Fire Water System	VII.G.A-412	3.3-1, 136	C
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Fire Water System	VII.G.A-722	3.3-1, 157	A
Valve body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.G.AP-234	3.3-1, 070	B
Valve body	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.G.AP-127	3.3-1, 097	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.G.AP-132	3.3-1, 069	B
Valve body	Pressure boundary	Copper alloy >15% Zn	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.AP-197	3.3-1, 064	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-47	3.3-1, 072	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Valve body	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	A
Valve body	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	Fire Water System	VII.G.A-722	3.3-1, 157	A
Valve body	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (int)	Loss of material	Fire Water System	VII.G.A-412	3.3-1, 136	C
Valve body	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	Fire Water System	VII.G.A-722	3.3-1, 157	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection	VII.G.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-33	3.3-1, 064	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching	VII.G.A-51	3.3-1, 072	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VII.I.AP-198	3.3-1, 109	A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-221c	3.3-1, 006	A

Table 3.3.2-15: Fire Protection — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.G.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.G.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.G.AP-136	3.3-1, 071	B
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Fire Water System	VII.G.A-55	3.3-1, 066	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning - erosion	Fire Water System	VII.C1.A-409	3.3-1, 126	E, 1

Notes for Table 3.3.2-15

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

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.

Plant-Specific Notes for Table 3.3.2-15

1. The Fire Water System AMP is enhanced to manage the wall thinning due to erosion aging effect.
2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material due to wear for elastomeric components.
3. The Selective Leaching AMP is used to manage loss of material due to Selective Leaching for water that could pool at the bottom of lube oil coolers.

Table 3.3.2-16
Emergency Diesel Generator Cooling Water —
Summary of Aging Management Evaluation

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Flex hose	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Flex hose	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Flex hose	Pressure boundary	Elastomer	Treated water (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.C2.AP-259	3.3-1, 085	A
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-209b	3.3-1, 004	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-221b	3.3-1, 006	A
Flex hose	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Flex hose	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Closed Treated Water Systems	VII.C2.AP-186	3.3-1, 043	B
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	D
Heat exchanger (fins)	Heat transfer	Aluminum	Air – outdoor (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (fins)	Heat transfer	Aluminum	Air – outdoor (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.A-788c	3.3-1, 254	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (fins)	Heat transfer	Aluminum	Air – outdoor (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.A-771c	3.3-1, 242	A
Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-209b	3.3-1, 004	C
Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-221b	3.3-1, 006	C
Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.AP-209c	3.3-1, 004	C
Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.AP-221c	3.3-1, 006	C

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Air – outdoor (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.C2.AP-205	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-199	3.3-1, 046	D
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	VII.H2.AP-43	3.3-1, 072	C
Heat exchanger (water box)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (water box)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	D
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-221b	3.3-1, 006	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.3-1, 085	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	B
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	B
Pump casing	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	B
Sight glass	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Sight glass	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-199	3.3-1, 046	B
Sight glass	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	VII.H2.AP-43	3.3-1, 072	A
Sight glass	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	V.F.EP-15	3.2-1, 060	A
Sight glass	Pressure boundary	Glass	Treated water (int)	None	None	V.F.EP-29	3.2-1, 060	A
Tank	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tank	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	C
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	D
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	B
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.C2.A-52	3.3-1, 049	B
Tubing	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Closed Treated Water Systems	VII.C2.AP-186	3.3-1, 043	B
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-16: Emergency Diesel Generator Cooling Water — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-199	3.3-1, 046	B
Valve body	Pressure boundary	Copper alloy >15% Zn	Treated water (int)	Loss of material	Selective Leaching	VII.H2.AP-43	3.3-1, 072	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.3-1, 085	A

Notes for Table 3.3.2-16

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-17
Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Air motor	Pressure boundary	Aluminum alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Air motor	Pressure boundary	Aluminum alloy	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.A-451b	3.3-1, 189	A
Air motor	Pressure boundary	Aluminum alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.A-763b	3.3-1, 234	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	Pressure boundary	Stainless steel	Diesel exhaust (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.AP-128	3.3-1, 083	A
Expansion joint	Pressure boundary	Stainless steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.AP-104	3.3-1, 088	A
Filter element	Filter	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.A-722	3.3-1, 157	A
Filter element	Filter	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Filter housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.A-722	3.3-1, 157	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Filter housing	Pressure boundary	CASS	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Filter housing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Filter housing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Flex hose	Pressure boundary	Elastomer	Air – dry (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.A-504	3.3-1, 085	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flex hose	Pressure boundary	Elastomer	Air – dry (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.AP-103	3.3-1, 096	A
Flex hose	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Flex hose	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Flex hose	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Orifice	Throttle	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H2.AP-104	3.3-1, 088	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Elastomer	Air – dry (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.A-504	3.3-1, 085	A
Piping	Pressure boundary	Elastomer	Air – dry (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.F4.AP-103	3.3-1, 096	A
Piping	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components	VII.I.AP-102	3.3-1, 076	A
Piping	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-113	3.3-1, 082	A
Piping	Pressure boundary	Galvanized steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A, 1
Piping	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Piping and piping components	Pressure boundary	Carbon Steel	Diesel exhaust (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-34	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Aluminum alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Aluminum alloy	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.A-451b	3.3-1, 189	A
Piping and piping components	Structural integrity (attached)	Aluminum alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.A-763b	3.3-1, 234	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Structural integrity (attached)	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Tank	Pressure boundary	Aluminum alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	C
Tank	Pressure boundary	Aluminum alloy	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.A-451b	3.3-1, 189	C
Tank	Pressure boundary	Aluminum alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.A-763b	3.3-1, 234	A
Tank	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	C
Tank	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tank	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	C
Tank	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	C

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	C
Tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	C
Tubing	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Aluminum alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Aluminum alloy	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H2.A-451b	3.3-1, 189	A
Valve body	Pressure boundary	Aluminum alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H2.A-763b	3.3-1, 234	A
Valve body	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Cast iron	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-17: Emergency Diesel Generator Air — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A

Notes for Table 3.3.2-17

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes for Table 3.3.2-17

1. The internal environment of this piping is dry air; so while this piping is in an indoor uncontrolled area, condensation will not accumulate on the surface of the piping. Without the presence of moisture from condensation, the galvanized steel piping has no aging effects that require management.

Table 3.3.2-18
Emergency Diesel Generator Fuel and Lubricating Oil —
Summary of Aging Management Evaluation

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VII.I.A-426	3.3-1, 145	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Filter housing	Pressure boundary	Cast iron	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Filter housing	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Filter housing	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Filter housing	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Filter housing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Filter housing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Filter housing	Pressure boundary	CASS	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Filter housing	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B
Flame arrestor	Fire prevention	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Flame arrestor	Fire prevention	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.A-722	3.3-1, 157	C

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flex hose	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Flex hose	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Flex hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Flex hose	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B
Heat exchanger (channel head)	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (channel head)	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-202	3.3-1, 045	D

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-131	3.3-1, 098	A
Heat exchanger (tubes)	Heat transfer	Copper alloy	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis One-Time Inspection	VII.H2.A-791	3.3-1, 257	A
Heat exchanger (tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems	VII.F2.AP-205	3.3-1, 050	B
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-133	3.3-1, 099	C
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems	VII.H2.AP-199	3.3-1, 046	D
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-138	3.3-1, 100	A
Orifice	Throttle	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-138	3.3-1, 100	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Piping	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B
Pump casing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Pump casing	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Pump casing	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Cast iron	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Cast iron	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Sight glass	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Sight glass	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Sight glass	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Sight glass	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Air – indoor uncontrolled (int)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Fuel oil (int)	None	None	VII.J.AP-49	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Lubricating oil (int)	None	None	VII.J.AP-15	3.3-1, 117	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VII.H1.A-401	3.3-1, 128	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VII.H1.A-401	3.3-1, 128	A
Tank	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry	VII.H1.AP-105a	3.3-1, 070	B
Tubing	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Tubing	Pressure boundary	Copper alloy	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-132	3.3-1, 069	B
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.AP-209c	3.3-1, 004	A
Tubing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.AP-221c	3.3-1, 006	A
Tubing	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B
Tubing	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-138	3.3-1, 100	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.H1.A-722	3.3-1, 157	A
Valve body	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Valve body	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	CASS	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Cast iron	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VII.H2.AP-127	3.3-1, 097	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.H1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-136	3.3-1, 071	B

Notes for Table 3.3.2-18

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.3.2-19
Service Water 10 CFR 54.4(a)(2) Spatial Interactions —
Summary of Aging Management Evaluation

Table 3.3.2-19: Service Water 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VII.I.A-03	3.3-1, 012	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VII.I.AP-124	3.3-1, 015	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-19: Service Water 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Piping	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-270	3.3-1, 088	A
Piping	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Leakage boundary (spatial)	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Leakage boundary (spatial)	Copper alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-197	3.3-1, 064	E, 1

Table 3.3.2-19: Service Water 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-77	3.3-1, 078	A
Valve body	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VII.I.A-24	3.3-1, 080	A
Valve body	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VII.I.A-79	3.3-1, 009	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-270	3.3-1, 088	A
Valve body	Leakage boundary (spatial)	Copper alloy	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-197	3.3-1, 064	E, 1

Table 3.3.2-19: Service Water 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Leakage boundary (spatial)	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Notes for Table 3.3.2-19

A. rshConsistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. rshConsistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.3.2-19

1. rshThe Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material and flow blockage in copper alloy components exposed to an internal environment of raw water.

3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.3.4, Steam and Power Conversion Systems, as being subject to AMR. The systems or portions of systems that are addressed in this section are described in the indicated sections.

- Main Steam and Turbine Generators (Section 2.3.4.1)
- Feedwater and Blowdown (Section 2.3.4.2)
- Auxiliary Feedwater and Condensate Storage (Section 2.3.4.3)
- Steam and Power Conversion Systems in the Scope of 10 CFR 54.4(a)(2) for Spatial Interactions (Section 2.3.4.4)

3.4.2 Results

The following tables summarize the results of the AMR for the Steam and Power Conversion Systems:

Table 3.4.2-1, Main Steam and Turbine Generators — Summary of Aging Management Evaluation (includes main steam and turbine components requiring an AMR for 10 CFR 54.4(a)(2) spatial interactions)

Table 3.4.2-2, Feedwater and Blowdown — Summary of Aging Management Evaluation (includes feedwater and blowdown components requiring an AMR for 10 CFR 54.4(a)(2) spatial interactions)

Table 3.4.2-3, Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Table 3.4.2-4, Auxiliary Steam 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

Table 3.4.2-5, Condensate 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

Table 3.4.2-6, Feedwater Heater Drains and Vents 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

3.4.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.4.2.1.1 Main Steam and Turbine Generators

Materials

The materials of construction for the Main Steam and Turbine Generators components are:

- Carbon steel
- Copper alloy > 15% Zn
- Low-alloy steel
- Stainless steel

Environments

The Main Steam and Turbine Generators components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air – dry
- Air with borated water leakage
- Steam

Aging Effects Requiring Management

The following aging effects associated with the Main Steam and Turbine Generators components require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the Main Steam and Turbine Generators components:

- Bolting Integrity
- Boric Acid Corrosion
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- Water Chemistry

3.4.2.1.2 Feedwater and Blowdown

Materials

The materials of construction for the Feedwater and Blowdown components are:

- Carbon steel
- Coating
- Copper alloy
- Stainless steel

Environments

The Feedwater and Blowdown components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air – dry
- Air with borated water leakage
- Concrete
- Fuel oil
- Soil
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the Feedwater and Blowdown components require management:

- Cracking
- Cumulative fatigue damage
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the Feedwater and Blowdown components:

- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping and Tanks
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Fuel Oil Chemistry
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks
- One-Time Inspection
- Outdoor and Large Atmospheric Metallic Storage Tanks
- Water Chemistry

3.4.2.1.3 Auxiliary Feedwater and Condensate Storage

Materials

The materials of construction for the Auxiliary Feedwater and Condensate Storage components are:

- Carbon steel
- CASS
- Coating
- Copper alloy
- Gray cast iron
- Low-alloy steel
- Stainless steel

Environments

The Auxiliary Feedwater and Condensate Storage components are exposed to the following environments:

- Air – outdoor
- Air – dry
- Concrete
- Lubricating oil
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Auxiliary Feedwater and Condensate Storage components require management:

- Cracking
- Cumulative fatigue damage
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the Auxiliary Feedwater and Condensate Storage storage components:

- Bolting Integrity
- Compressed Air Monitoring
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Outdoor and Large Atmospheric Metallic Storage Tanks
- Selective Leaching
- Water Chemistry

3.4.2.1.4 Auxiliary Steam

Materials

The materials of construction for the Auxiliary Steam components are:

- Carbon steel

Environments

The Auxiliary Steam components are exposed to the following environments:

- Air – outdoor
- Steam

Aging Effects Requiring Management

The following aging effects associated with the Auxiliary Steam components require management:

- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the Auxiliary Steam components:

- Bolting Integrity
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- One-Time Inspection
- Water Chemistry

3.4.2.1.5 Condensate

Materials

The materials of construction for the Condensate components are:

- Carbon steel
- Stainless steel

Environments

The Condensate components are exposed to the following environments:

- Air – outdoor
- Steam
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the Condensate components require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the Condensate components:

- Bolting Integrity
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- One-Time Inspection
- Water Chemistry

3.4.2.1.6 Feedwater Heater Drains and Vents

Materials

The materials of construction for the Feedwater Heater Drains and Vents components are:

- Carbon steel
- Stainless steel

Environments

The Feedwater Heater Drains and Vents components are exposed to the following environments:

- Air – outdoor
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the Feedwater Heater Drains and Vents components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Feedwater Heater Drains and Vents components:

- Bolting Integrity
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- One-Time Inspection
- Water Chemistry

3.4.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the SLRA. For the Steam and Power Conversion Systems, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.4.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in SRP-SLR Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses." For plant-specific cumulative usage factor *calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.*

Cumulative fatigue damage of Steam and Power Conversion Systems components, as described in SRP-SLR Item 3.4.2.2.1, are addressed as a TLAA in Section 4.3.2, Metal Fatigue of Piping Components.

3.4.2.2.2 Cracking due to Stress Corrosion Cracking (SCC) 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 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.

Stress corrosion cracking is to an aging effect requiring management provided 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.

Steam and Power Conversion Systems contain stainless steel piping, piping components, heat exchanger components, bolting and tanks exposed to both uncontrolled indoor air and outdoor air. A review of Turkey Point OE confirms the presence of halides in both the indoor and outdoor environments at Turkey Point. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air in the Steam and Power Conversion Systems are susceptible to cracking due to SCC and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed via the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and the External Surfaces Monitoring of Mechanical Components AMP for components exposed to air internally or externally, respectively. The exception to this is bolting, which is managed by the Bolting Integrity AMP. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is used to manage the integrity barrier coatings. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks and Bolting Integrity AMPs are 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.

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.

Loss of material due to pitting and crevice corrosion is not an aging effect requiring management provided 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.*

Steam and Power Conversion Systems contain stainless steel piping, piping components, heat exchanger components, and tanks exposed to both uncontrolled indoor air and outdoor air. A review of Turkey Point OE confirms the presence of halides in both the indoor and outdoor environments at Turkey Point. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air in the Steam and Power Conversion Systems are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material in these components will be managed via the External Surfaces Monitoring of Mechanical Components AMP for components exposed to air externally. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is used to manage the integrity barrier coatings. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components and Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMPs are described in Appendix B. There are no stainless steel components exposed to an underground environment in the steam and power conversion systems.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2, of this SRP-SLR).

Quality Assurance provisions applicable to SLR are discussed in Appendix B.

3.4.2.2.5 Ongoing Review of Operating Experience

The Operating Experience process and acceptance criteria are described in Appendix B.

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.

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.

As there are no metallic piping or piping components in the Steam and Power Conversion Systems that are exposed to raw water or waste water, recurring internal corrosion is not an applicable aging effect for the Steam and Power Conversion Systems. As such, credited Turkey Point AMPs, such as Fire Water System, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Open-Cycle Cooling Water System, do not require augmentation for detection of aging effects prior to functional impact.

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 one of the two necessary conditions discussed below is absent.*

<u>Susceptible Material</u>: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

<u>Aggressive Environment</u>: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such

as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

As the Steam and Power Conversion Systems do not contain any aluminum or aluminum alloy components, cracking of aluminum is not an applicable aging effect.

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.

As the Steam and Power Conversion Systems do not contain any steel or stainless steel piping or piping components exposed to concrete, loss of material and cracking of steel or stainless steel exposed to concrete is not an applicable aging effect.

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.*

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.

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.

As the Steam and Power Conversion Systems do not contain any aluminum components, loss of material in aluminum alloys is not an applicable aging effect.

3.4.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Steam and Power Conversion Systems components:

- Section 4.3.2, Metal Fatigue of Piping Components

3.4.3 Conclusion

Steam and Power Conversion Systems piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for Steam and Power Conversion Systems components are identified in the summaries in Section 3.4.2 above.

A description of these AMPs is provided in Appendix B along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with Steam and Power Conversion 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 SPEO.

Table 3.4-1
Summary of Aging Management Evaluations
for the Steam and Power Conversion Systems

Table 3.4-1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 001	Steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.4.2.2.1)	Cumulative fatigue damage is an aging effect assessed by a fatigue TLAA. Further evaluation is documented in Section 3.4.2.2.1.
3.4-1, 002	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage loss of material of stainless steel piping, piping components, and piping elements exposed to air. Further evaluation is documented in Section 3.4.2.2.2.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 003	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs will be used to manage loss of material of stainless steel piping, piping components, and tanks exposed to air internally. Further evaluation is documented in Section 3.4.2.2.3.
3.4-1, 004	Steel external surfaces exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion AMP will be used to manage loss of material of steel surfaces exposed to air with borated water leakage.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 005	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191 for steel piping components. This line item has also been applied to heat exchanger components. The Flow-Accelerated Corrosion AMP is used to monitor steel piping, piping components, and heat exchanger components exposed to steam or treated water.
3.4-1, 006	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage loss of preload of metallic closure bolting in any environment.
3.4-1, 007	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There is no high-strength steel closure bolting in the Steam and Power Conversion Systems.
3.4-1, 008	There is no 3.4-1, 008 in NUREG-2192.				

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 009	Steel, stainless steel, nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage loss of material of stainless steel, steel, and nickel alloy closure bolting exposed to condensation or uncontrolled air environments.
3.4-1, 010	There is no 3.4-1, 010 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. The Water Chemistry and One-Time Inspection AMPs will be used to manage cracking of stainless steel piping, piping components, and heat exchanger components exposed to steam or treated water >60°C (>140°F).
3.4-1, 012	Steel tanks exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry and One-Time Inspection AMPs are used to monitor the steel steam generator blowdown tanks which are exposed to treated water.
3.4-1, 013	There is no 3.4-1, 013 in NUREG-2192.				

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 014	Steel piping, piping components exposed to steam, treated water	Loss of material due to general, pitting, crevice corrosion, MIC (treated water only)	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry and One-Time Inspection AMPs are used to monitor steel piping, piping components, and the turbine housing exposed to steam or treated water.
3.4-1, 015	Steel heat exchanger components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry and One-Time Inspection AMPs are used to monitor steel heat exchanger components exposed to steam or treated water.
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 for material, environment, aging effect, and management AMP, but this item is applied to heat exchanger components. The Water Chemistry and One-Time Inspection AMPs will be used to manage loss of material of copper alloy heat exchanger components exposed to treated water.
3.4-1, 017	There is no 3.4-1, 017 in NUREG-2192.				

Table 3.4-1: 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. The Water Chemistry and One-Time Inspection AMPs will be used to manage reduction of heat transfer in copper alloy heat exchanger components exposed to treated water.
3.4-1, 019	Stainless steel, steel heat exchanger components exposed to raw water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no steel or stainless steel heat exchanger components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 020	Copper alloy, stainless steel piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no copper alloy or stainless steel piping or piping components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 021	There is no 3.4-1, 021 in NUREG-2192.				

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 022	Stainless steel, copper alloy, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no copper alloy, stainless steel, or steel heat exchanger tubes exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 023	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not used. While there are stainless steel piping and piping components exposed to treated water >60°C (>140°F), these items are addressed under the applicable treated water entries and managed using the Water Chemistry and One-Time Inspection AMPs.
3.4-1, 024	There is no 3.4-1, 024 in NUREG-2192.				

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 025	Steel heat exchanger components exposed to closed- cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not used. While there are steel heat exchanger components exposed to treated water, these items are addressed under the applicable treated water entries and managed using the Water Chemistry and One-Time Inspection programs.
3.4-1, 026	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems AMP is used to manage loss of material in stainless steel heat exchanger components exposed to treated water. All of these components are located in the auxiliary 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 or piping components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 028	Steel, stainless steel, copper alloy heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. The Steam and Power Conversion Systems do not contain heat exchanger tubes exposed to closed-cycle cooling water.
3.4-1, 029	There is no 3.4-1, 029 in NUREG-2192.				
3.4-1, 030	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material in steel tanks (condensate storage tank and demineralized water storage tank) exposed to air or concrete.
3.4-1, 031	There is no 3.4-1, 031 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 or piping components exposed to soil in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 for material, environment, aging effect, and management AMP, but this item is also applied to heat exchanger components at Turkey Point. The Selective Leaching AMP will be used to manage loss of material of gray cast iron heat exchanger components exposed to treated water.
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 AMP is used to manage the loss of material in external steel surfaces exposed to air or condensation.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 035	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum piping or piping components in the Steam and Power Conversion Systems.
3.4-1, 036	Steel piping, piping components exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage the loss of material in internal steel surfaces exposed to air or condensation.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 037	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel piping or piping components that have an internal environment of condensation in the Steam and Power Conversion Systems.
3.4-1, 038	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no steel piping or piping components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 039	There is no 3.4-1, 039 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	Consistent with NUREG-2191. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage the loss of material in steel piping and piping components exposed to lubricating oil.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 041	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage the loss of material in steel heat exchanger components exposed to lubricating oil.
3.4-1, 042	Aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum piping or piping components in the Steam and Power Conversion Systems.
3.4-1, 043	Copper alloy piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 for material, environment, aging effect, and management AMP, but this item is applied to heat exchanger components. The Lubricating Oil Analysis and One-Time Inspection AMPs will be used to manage loss of material of copper alloy exposed to lubricating oil.

Table 3.4-1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 044	Stainless steel piping, piping components, heat exchanger components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage the loss of material in stainless steel piping, piping components, and heat exchanger components exposed to lubricating oil.
3.4-1, 045	Aluminum heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum heat exchanger tubes in the Steam and Power Conversion Systems.
3.4-1, 046	Stainless steel, steel, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage reduction of heat transfer in stainless steel and copper heat exchanger tubes exposed to lubricating oil.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 047	Stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP are used to manage loss of material in stainless steel piping, piping components, tanks, and closure bolting exposed to soil.
3.4-1, 048	Nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no nickel alloy components in the Steam and Power Conversion Systems.
3.4-1, 049	There is no 3.4-1, 049 in NUREG-2192.				
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 components exposed to soil, concrete, or located underground that fall within the scope of Buried and Underground Piping and Tanks in the Steam and Power Conversion Systems.
3.4-1, 050a	There is no 3.4-1, 050a in NUREG-2192.				

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 051	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. There are no steel piping or piping components exposed to concrete in the Steam and Power Conversion Systems.
3.4-1, 052	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 053	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no copper alloy piping or 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. Copper alloy piping and piping components exposed to air do not have any aging effects that require management.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 055	Glass piping elements exposed to lubricating oil, air, condensation, raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water	None	None	No	Not applicable. There are no glass components in the Steam and Power Conversion Systems.
3.4-1, 056	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no nickel alloy components in the Steam and Power Conversion Systems.
3.4-1, 057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not applicable. There are no PVC components in the Steam and Power Conversion Systems.
3.4-1, 058	Stainless steel piping, piping components exposed to gas	None	None	No	Not applicable. There are no stainless steel components exposed to gas in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not applicable. There are no steel components exposed to controlled indoor air 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 for metallic piping and piping components. This line item is also used for managing wall thinning due to erosion in heat exchanger tubes. The Flow-Accelerated Corrosion AMP is used to manage wall thinning due to erosion in metallic piping, piping components, and heat exchanger tubes exposed to steam and treated water.
3.4-1, 061	Metallic piping, piping components, tanks exposed to raw water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.4.2.2.6)	Not applicable. There are no components exposed to raw water or waste water in the Steam and Power Conversion Systems. Further evaluation is documented in Section 3.4.2.2.6.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material in steel tanks exposed to treated water.
3.4-1, 063	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage insulated steel piping and piping components exposed to air or condensation.
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. There is no thermal insulation in the scope of SLR in the Steam and Power Conversion Systems.
3.4-1, 065	There is no 3.4-1, 065 in NUREG-2192.				

Table 3.4-1: 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	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be used to manage loss of coating for tanks with internal coatings exposed to treated water.
3.4-1, 067	Any material piping, piping components, heat exchangers, tanks with internal coatings/ linings exposed to closed- cycle cooling water, raw water, treated water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not used. Material coatings and underlying materials have been addressed using the appropriate line items for coatings and the underlying materials.
3.4-1, 068	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. There are no gray cast iron or ductile iron piping or piping components with internal coatings in the Steam and Power Conversion Systems.
3.4-1, 069	There is no 3.4-1, 069 in NUREG-2192.				

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 070	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water, waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There are no closure bolting in the Steam and Power Conversion Systems exposed to raw water.
3.4-1, 071	There is no 3.4-1, 071 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	Not used. The components exposed to soil or concrete in the Steam and Power Conversion Systems are addressed under item numbers 3.4-1, 030 and 3.4-1, 047.
3.4-1, 073	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity AMP will be used to manage cracking of stainless steel bolting exposed to air.

Table 3.4-1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 074	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. As no underground stainless steel is exposed to groundwater, cracking is not a concern for underground piping, piping components, or tanks included in the Steam and Power Conversion Systems.
3.4-1, 075	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no heat exchanger tubes exposed to air or condensation in the Steam and Power Conversion Systems.
3.4-1, 077	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no elastomer components in the Steam and Power Conversion Systems.
3.4-1, 078	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer components in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 080	There is no 3.4-1, 080 in NUREG-2192.				
3.4-1, 081	Steel components exposed to treated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 082	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. There are no stainless steel components exposed to concrete in the Steam and Power Conversion Systems.
3.4-1, 083	Stainless steel, nickel alloy tanks exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel or nickel alloy tanks exposed to treated water in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 084	Stainless steel, nickel alloy piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 for metallic piping and piping components. This line item is also used for managing loss of material in stainless steel heat exchanger tubes. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material of stainless steel piping, piping components, and heat exchanger tubes.
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. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material in stainless steel piping, piping components, and heat exchanger components exposed to treated water.
3.4-1, 086	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes internal to components exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no heat exchanger tubes exposed to air or condensation in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 088	There is no 3.4-1, 088 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 components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 090	Steel, stainless steel, copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 091	Steel, stainless steel, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no components exposed to raw water in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 092	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no copper piping or piping components exposed to soil in the Steam and Power Conversion Systems.
3.4-1, 093	There is no 3.4-1, 093 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 (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 095	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Not used. The stainless steel piping exposed to soil is addressed by a different line item, and there are no nickel alloy piping, piping components, or tanks in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 components in the 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 (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.

Table 3.4-1: 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 (SRP-SLR Section 3.4.2.2.3)	Not applicable. There are no stainless steel or nickel alloy tanks in the Steam and Power Conversion Systems.
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 exposed to soil or concrete in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 100	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no stainless steel tanks in the Steam and Power Conversion Systems.
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 exposed to soil or concrete in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 103	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage loss of material of stainless steel piping, piping components, and tanks exposed to air externally. Further evaluation is documented in Section 3.4.2.2.3.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 104	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage loss of material of stainless steel piping, piping components, and piping elements exposed to air. Further evaluation is documented in Section 3.4.2.2.2.

Table 3.4-1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 105	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
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 used. Cracking of copper alloys depends on the presence of ammonia or ammonia compound. A review of Turkey Point OE confirms that neither ammonia nor ammonia compounds are present
3.4-1, 107	Copper alloy (>15% Zn or >8% Al) tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no copper alloy tanks in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 108	There is no 3.4-1, 108 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 (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 110	There is no 3.4-1, 110 in NUREG-2192.				
3.4-1, 111	There is no 3.4-1, 111 in NUREG-2192.				

Table 3.4-1: 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 (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 113	There is no 3.4-1, 113 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	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.
3.4-1, 115	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 116	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the 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 components in the Steam and Power Conversion Systems.
3.4-1, 118	There is no 3.4-1, 118 in NUREG-2192.				
3.4-1, 119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 120	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 121	There is no 3.4-1, 121 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 components in the Steam and Power Conversion Systems.

Table 3.4-1: 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 components in the 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 components 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 components in the Steam and Power Conversion Systems.
3.4-1, 126	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed- cycle cooling water	None	None	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.

Table 3.4-1: 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 components 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 components exposed to concrete in the Power and Steam Conversion Systems.
3.4-1, 129	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no copper components exposed to soil or underground in the 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	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 131	Copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Not applicable. There are no copper components exposed to air with borated water leakage in the Power and Steam Conversion Systems.
3.4-1, 132	Stainless steel piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not used. The environment and material combination do exist. However, this SLRA does not list combinations in the Table 2s that have no aging effects unless there is only one environment applicable to that component type and material.
3.4-1, 133	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.

Table 3.4-1: Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 134	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.
3.4-1, 135	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no polymeric components in the Steam and Power Conversion Systems.

Table 3.4.2-1
Main Steam and Turbine Generators —
Summary of Aging Management Evaluation

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air-outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air-outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VIII.H.S-421	3.4-1, 073	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VIII.H.S-421	3.4-1, 073	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Flow element (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Flow element	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A
Flow element	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Flow element	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.B1.S-15	3.4-1, 005	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Flow element (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Flow element	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	A
Flow element	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	A
Flow element	Pressure boundary	Stainless steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Flow element	Throttle	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A
Flow element	Throttle	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Flow element	Throttle	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.B1.S-15	3.4-1, 005	A
Flow element	Throttle	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Throttle	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	A
Flow element	Throttle	Stainless steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.A.SP-71	3.4-1, 014	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.A.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.A.S-15	3.4-1, 005	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Piping	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A
Piping	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Piping	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.B1.S-15	3.4-1, 005	A
Piping	Pressure boundary	Low-alloy steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Low-alloy steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Piping	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	A
Piping	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	A
Piping	Pressure boundary	Stainless steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Low-alloy steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Pressure boundary	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Pressure boundary	Low-alloy steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Pressure boundary	Stainless steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.B1.S-08	3.4-1, 001	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.B1.S-15	3.4-1, 005	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VIII.B1.SP-59	3.4-1, 036	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	V.A.E-29	3.2-1, 044	A
Piping and piping components (insulated)	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components (insulated)	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Tubing	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Tubing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Tubing	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A
Tubing	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Tubing	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.B1.S-15	3.4-1, 005	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	None	None	VIII.I.SP-6	3.4-1, 054	A
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-118b	3.4-1, 002	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-127b	3.4-1, 003	A
Tubing	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	A
Tubing	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	A
Tubing	Pressure boundary	Stainless steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Tubing (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Tubing (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Tubing (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.A.SP-71	3.4-1, 014	A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.A.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.A.S-15	3.4-1, 005	A
Valve body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Valve body	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A
Valve body	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.B1.S-15	3.4-1, 005	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	None	None	VIII.I.SP-6	3.4-1, 054	A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-118b	3.4-1, 002	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.B1.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.B1.SP-98	3.4-1, 011	A
Valve body	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-155	3.4-1, 084	A

Table 3.4.2-1: Main Steam and Turbine Generators — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.B1.S-408	3.4-1, 060	A
Valve body (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Valve body (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Valve body (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A

Notes for Table 3.4.2-1

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.4.2-2
Feedwater and Blowdown — Summary of Aging Management Evaluation

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VIII.H.S-421	3.4-1, 073	A
Bolting	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity	VIII.H.S-421	3.4-1, 073	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VIII.H.S-421	3.4-1, 073	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flame arrestor	Fire prevention	Carbon steel	Air-outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VIII.E.SP-59	3.4-1, 036	C
Flame arrestor	Fire prevention	Carbon steel	Air-outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Flow element	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Flow element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Flow element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Flow element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Flow element	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Flow element	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-77	3.4-1, 015	A
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	C
Heat exchanger (channel head)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (tube sheet)	Pressure boundary	Carbon steel	Treated water (ext)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-77	3.4-1, 015	A
Heat exchanger (tube sheet)	Pressure boundary	Carbon steel	Treated water (ext)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	C
Heat exchanger (tube sheet)	Pressure boundary	Carbon steel	Treated water (ext)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (tube sheet)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-77	3.4-1, 015	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (tube sheet)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	C
Heat exchanger (tube sheet)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water >140°F (ext)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	C
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	C

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Orifice	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Orifice	Throttle	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Orifice	Throttle	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.D1.S-11	3.4-1, 001	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A
Piping	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Piping	Pressure boundary	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks	VIII.H.SP-145	3.4-1, 047	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components (insulated)	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Piping and piping components (insulated)	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Pump casing	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump casing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Pump casing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Pump casing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Pump casing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Strainer body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Strainer body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Strainer body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer body	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Strainer body	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A
Tank	Pressure boundary	Carbon steel	Air-outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VIII.G.SP-116	3.4-1, 030	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VIII.G.SP-116	3.4-1, 030	A
Tank	Pressure boundary	Carbon steel	Concrete	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VIII.G.SP-116	3.4-1, 030	A
Tank	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VIII.G.S-405	3.4-1, 062	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Coating	Treated water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VIII.G.S-401	3.4-1, 066	A
Tank	Structural Integrity (attached)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Tank (insulated)	Structural Integrity (attached)	Carbon steel	Air-indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Tank	Structural Integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-75	3.4-1, 012	A
Tank	Structural Integrity (attached)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Tank	Structural Integrity (attached)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Tubing	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A
Tubing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Tubing (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Tubing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Tubing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Tubing	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Tubing	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Tubing	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A
Tubing (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Tubing (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Valve body	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Valve body	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry One-Time Inspection	VII.H1.AP-105	3.3-1, 070	B
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	VIII.H.S-30	3.4-1, 004	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-74	3.4-1, 014	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Copper alloy	Air – dry (int)	None	None	VIII.I.SP-6	3.4-1, 054	A
Valve body	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VIII.I.SP-6	3.4-1, 054	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A

Table 3.4.2-2: Feedwater and Blowdown — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-118b	3.4-1, 002	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.D1.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.D1.SP-87	3.4-1, 085	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.D1.SP-88	3.4-1, 011	A

Notes for Table 3.4.2-2

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.4.2-3
Auxiliary Feedwater and Condensate Storage —
Summary of Aging Management Evaluation

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity	VIII.H.S-421	3.4-1, 073	A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-127b	3.4-1, 003	A
Flow element	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-118b	3.4-1, 002	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Throttle	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Heat exchanger (channel head)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching	VIII.G.SP-27	3.4-1, 033	C
Heat exchanger (channel head)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-77	3.4-1, 015	A
Heat exchanger (channel head)	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-76	3.4-1, 041	A
Heat exchanger (shell)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Heat exchanger (tubes)	Heat transfer	Copper alloy	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-99	3.4-1, 046	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	VIII.G.SP-100	3.4-1, 018	A
Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated water (int)	Reduction of heat transfer	Water Chemistry One-Time Inspection	VIII.F.SP-96	3.4-1, 018	A
Heat exchanger (tubes)	Heat transfer	Stainless steel	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-102	3.4-1, 046	A
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-92	3.4-1, 043	A
Heat exchanger (tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.F.SP-101	3.4-1, 016	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-79	3.4-1, 044	A
Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Heat exchanger (tube sheet)	Pressure boundary	Copper alloy	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-92	3.4-1, 043	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (tube sheet)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.F.SP-101	3.4-1, 016	A
Heat exchanger (tube sheet)	Pressure boundary	Stainless steel	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-79	3.4-1, 044	A
Heat exchanger (tube sheet)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-127b	3.4-1, 003	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-118b	3.4-1, 002	A
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Piping	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.G.S-16	3.4-1, 005	A
Piping	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-91	3.4-1, 040	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping	Pressure boundary	Low-alloy steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 085	A
Piping (insulated)	Pressure boundary	Low-alloy steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.G.SP-88	3.4-1, 011	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VIII.G.SP-127c	3.4-1, 003	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VIII.G.SP-118c	3.4-1, 003	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-127b	3.4-1, 003	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-118b	3.4-1, 003	A
Piping and piping components	Pressure boundary	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.G.S-11	3.4-1, 001	A
Piping and piping components	Pressure boundary	Low-alloy steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.G.S-11	3.4-1, 001	A
Piping and piping components	Pressure boundary	Stainless steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.G.S-11	3.4-1, 001	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.G.S-16	3.4-1, 005	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Piping and piping components (insulated)	Structural integrity (attached)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.G.SP-88	3.4-1, 011	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VII.E1.A-57	3.3-1, 002	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Pump Casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A
Pump Casing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Pump Casing	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-91	3.4-1, 040	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VIII.G.SP-116	3.4-1, 030	A
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VIII.G.S-405	3.4-1, 062	A
Tank	Pressure boundary	Carbon steel	Concrete	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks	VIII.G.SP-116	3.4-1, 030	A
Tank	Pressure boundary	Coating	Treated water (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VIII.G.S-401	3.4-1, 066	A
Tubing	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A
Tubing	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-95	3.4-1, 040	A
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Tubing	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry One-Time Inspection	VIII.G.SP-88	3.4-1, 011	A
Tubing	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-127b	3.4-1, 003	A
Tubing (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-451c	3.4-1, 103	A
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-118b	3.4-1, 002	A
Tubing (insulated)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.H.S-452c	3.4-1, 104	A
Turbine housing	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.G.S-16	3.4-1, 005	A
Turbine housing	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A
Turbine housing (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A
Valve Body	Pressure boundary	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.G.S-16	3.4-1, 005	A
Valve Body (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Valve Body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-74	3.4-1, 014	A
Valve Body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-29	3.4-1, 034	A
Valve Body	Pressure boundary	CASS	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Valve Body	Pressure boundary	CASS	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-127b	3.4-1, 003	A
Valve Body	Pressure boundary	CASS	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-118b	3.4-1, 002	A

Table 3.4.2-3: Auxiliary Feedwater and Condensate Storage — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure boundary	Copper alloy	Air – dry (int)	None	None	VIII.I.SP-6	3.4-1, 054	A
Valve Body	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VIII.I.SP-6	3.4-1, 054	A
Valve Body	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis One-Time Inspection	VIII.G.SP-95	3.4-1, 040	A
Valve Body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-127b	3.4-1, 003	A
Valve Body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.G.SP-118b	3.4-1, 002	A
Valve Body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.G.SP-87	3.4-1, 085	A
Valve Body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring	VII.D.A-764	3.3-1, 235	A

Notes for Table 3.4.2-3

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.4.2-4
Auxiliary Steam 10 CFR 54.4(a)(2) Spatial Interactions —
Summary of Aging Management Evaluation

Table 3.4.2-4: Auxiliary Steam 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.A.SP-71	3.4-1, 014	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.A.S-15	3.4-1, 005	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.B1.S-08	3.4-1, 001	A

Table 3.4.2-4: Auxiliary Steam 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.B1.SP-71	3.4-1, 014	A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.B1.S-15	3.4-1, 005	A

Notes for Table 3.4.2-4

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.4.2-5
Condensate 10 CFR 54.4(a)(2) Spatial Interactions —
Summary of Aging Management Evaluation

Table 3.4.2-5: Condensate 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Orifice	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.E.SP-88	3.4-1, 011	A
Orifice	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-87	3.4-1, 085	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air-outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.E.SP-118b	3.4-1, 002	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air-outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.E.SP-127b	3.4-1, 003	A

Table 3.4.2-5: Condensate 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-73	3.4-1, 014	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.E.S-16	3.4-1, 005	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.D1.S-11	3.4-1, 001	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.E.S-16	3.4-1, 005	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-73	3.4-1, 014	A

Table 3.4.2-5: Condensate 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.E.SP-73	3.4-1, 014	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.E.S-16	3.4-1, 005	A

Notes for Table 3.4.2-5

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.4.2-6
Feedwater Heater, Drains, and Vents 10 CFR 54.4(a)(2) Spatial Interactions —
Summary of Aging Management Evaluation

Table 3.4.2-6: Feedwater Heater, Drains, and Vents 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity	VIII.H.S-02	3.4-1, 009	A
Bolting	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity	VIII.H.SP-142	3.4-1, 006	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated water >140^{0}F (int)	Cracking	Water Chemistry One-Time Inspection	VIII.C.SP-88	3.4-1, 011	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.C.SP-87	3.4-1, 085	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	VIII.C.SP-118b	3.4-1, 002	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.C.SP-127b	3.4-1, 003	A

Table 3.4.2-6: Feedwater Heater, Drains, and Vents 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.C.SP-73	3.4-1, 014	A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA –Section 4.3.2, Metal Fatigue of Piping Components	VIII.D1.S-11	3.4-1, 001	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.C.SP-73	3.4-1, 014	A

Table 3.4.2-6: Feedwater Heater, Drains, and Vents 10 CFR 54.4(a)(2) Spatial Interactions — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - FAC	Flow-Accelerated Corrosion	VIII.D1.S-16	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning - erosion	Flow-Accelerated Corrosion	VIII.D1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry One-Time Inspection	VIII.C.SP-73	3.4-1, 014	A
Valve body (insulated)	Leakage boundary (spatial)	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	VIII.H.S-402a	3.4-1, 063	A

Notes for Table 3.4.2-6

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

3.5 AGING MANAGEMENT OF CONTAINMENTS, STRUCTURES, AND COMPONENT SUPPORTS

3.5.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.4, Scoping and Screening Results: Structures, as being subject to AMR. The structures or structural components that are addressed in this section are described in the indicated sections.

- Containment Structure and Internal Structural Components (Sections 2.4.1.1 and 2.4.1.2)
- Auxiliary Building (Section 2.4.2.1)
- Cold Chemistry Lab (Section 2.4.2.2)
- Control Building (Section 2.4.2.3)
- Cooling Water Canals (Section 2.4.2.4)
- Diesel Driven Fire Pump Enclosure (Section 2.4.2.5)
- Discharge Structure (Section 2.4.2.6)
- Electrical Penetration Rooms (Section 2.4.2.7)
- Emergency Diesel Generator Buildings (Section 2.4.2.8)
- Fire Rated Assemblies (Section 2.4.2.9)
- Intake Structure (Section 2.4.2.10)
- Main Steam and Feedwater Platforms (Section 2.4.2.11)
- Plant Vent Stack (Section 2.4.2.12)
- Polar Cranes (Section 2.4.2.13)
- Spent Fuel Storage and Handling (Section 2.4.2.14)
- Turbine Building (Section 2.4.2.15)
- Turbine Gantry Cranes (Section 2.4.2.16)
- Yard Structures (Section 2.4.2.17)

3.5.2 Results

The following tables summarize the results of the AMR for Containment, Structures and Component Supports:

Table 3.5.2-1, Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Table 3.5.2-2, Auxiliary Building — Summary of Aging Management Evaluation

Table 3.5.2-3, Cold Chemistry Lab — Summary of Aging Management Evaluation

Table 3.5.2-4, Control Building — Summary of Aging Management Evaluation

Table 3.5.2-5, Cooling Water Canals — Summary of Aging Management Evaluation

Table 3.5.2-6, Diesel Driven Fire Pump Enclosure — Summary of Aging Management Evaluation

Table 3.5.2-7, Discharge Structure — Summary of Aging Management Evaluation

Table 3.5.2-8, Electrical Penetration Rooms — Summary of Aging Management Evaluation

Table 3.5.2-9, Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Table 3.5.2-10, Fire Rated Assemblies — Summary of Aging Management Evaluation

Table 3.5.2-11, Intake Structure — Summary of Aging Management Evaluation

Table 3.5.2-12, Main Steam and Feedwater Platforms — Summary of Aging Management Evaluation

Table 3.5.2-13, Plant Vent Stack — Summary of Aging Management Evaluation

Table 3.5.2-14, Polar Cranes — Summary of Aging Management Evaluation

Table 3.5.2-15, Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Table 3.5.2-16, Turbine Building — Summary of Aging Management Evaluation

Table 3.5.2-17, Turbine Gantry Cranes — Summary of Aging Management Evaluation

Table 3.5.2-18, Yard Structures — Summary of Aging Management Evaluation

3.5.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.5.2.1.1 Containment Structure and Internal Structural Components

Materials

The materials of construction for the Containment Structure and Internal Structural Components are:

- Carbon steel
- Coatings
- Concrete
- Dissimilar metal weld
- Elastomer, rubber and other similar materials
- Galvanized steel
- Grout
- High-strength steel
- Lubrite
- Stainless steel

Environments

The Containment Structure and Internal Structural Components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater/soil

Aging Effect Requiring Management

The following aging effects associated with the Containment Structure and Internal Structural Components require management:

- Cracking
- Cumulative fatigue damage
- Increase in porosity and permeability
- Loss of bond
- Loss of coating or lining integrity
- Loss of leak tightness
- Loss of material
- Loss of mechanical function
- Loss of preload
- Loss of prestress
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction or loss of isolation function

Aging Management Programs

The following AMPs manage the aging effects for the Containment Structure and Internal Structural Components:

- 10 CFR Part 50, Appendix J
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWF
- ASME Section XI, Subsection IWL
- Boric Acid Corrosion
- Fire Protection
- Protective Coating Monitoring and Maintenance
- Structures Monitoring

3.5.2.1.2 Auxiliary Building

Materials

The materials of construction for the Auxiliary Building components are:

- Aluminum
- Carbon steel
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Galvanized steel
- Grout
- Stainless steel

Environments

The Auxiliary Building components are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater/soil

Aging Effect Requiring Management

The following aging effects associated with the Auxiliary Building components require management:

- Cracking
- Cumulative fatigue damage
- Deformation
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Auxiliary Building components:

- Boric Acid Corrosion
- Fire Protection

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Masonry Walls
- Structures Monitoring

3.5.2.1.3 Cold Chemistry Lab

Materials

The materials of construction for the Cold Chemistry Lab components are:

- Concrete

Environments

The Cold Chemistry Lab components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Cold Chemistry Lab components require management:

- Cracking
- Loss of bond
- Loss of material
- Increase in porosity and permeability

Aging Management Program

The following AMP manages the aging effects for the Cold Chemistry Lab components:

- Structures Monitoring

3.5.2.1.4 Control Building

Materials

The materials of construction for the Control Building components are:

- Carbon steel
- Concrete

- Concrete block
- Carbon steel
- Elastomer, rubber and other similar materials
- Galvanized steel
- Grout
- Gypsum board, acoustical panels
- Stainless steel
- Tee Cor panel, Micarta, cove base, steel supports

Environments

The Control Building components are exposed to the following environments:

- Air – indoor controlled
- Air – outdoor
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Control Building components require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Control Building components:

- Fire Protection
- Masonry Walls
- Structures Monitoring

3.5.2.1.5 Cooling Water Canals

Materials

The materials of construction for the Cooling Water Canals components are:

- Various

Environments

The Cooling Water Canals components are exposed to the following environments:

- Air – outdoor
- Water – flowing or standing

Aging Effect Requiring Management

The following aging effects associated with the Cooling Water Canals components require management:

- Loss of form
- Loss of material

Aging Management Program

The following AMP manages the aging effects for the Cooling Water Canals components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants

3.5.2.1.6 Diesel Driven Fire Pump Enclosure

Materials

The materials of construction for the Diesel Driven Fire Pump Enclosure components are:

- Aluminum
- Carbon steel
- Concrete
- Galvanized steel
- Grout

Environments

The Diesel Driven Fire Pump Enclosure components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Diesel Driven Fire Pump Enclosure components require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Reduction in concrete anchor capacity

Aging Management Program

The following AMP manages the aging effects for the Diesel Driven Fire Pump Enclosure components:

- Structures Monitoring

3.5.2.1.7 Discharge Structure

Materials

The materials of construction for the Discharge Structure components are:

- Carbon steel
- Concrete
- Galvanized steel
- Grout

Environments

The Discharge Structure components are exposed to the following environments:

- Air – outdoor
- Groundwater/soil
- Water – flowing or standing

Aging Effect Requiring Management

The following aging effects associated with the Discharge Structure components require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond

- Loss of material
- Loss of preload
- Loss of strength
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Discharge Structure components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Structures Monitoring

3.5.2.1.8 Electrical Penetration Rooms

Materials

The materials of construction for the Electrical Penetration Rooms components are:

- Carbon steel
- Concrete
- Elastomer, rubber and other similar materials
- Galvanized steel
- Grout

Environments

The Electrical Penetration Rooms components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Electrical Penetration Rooms components require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Electrical Penetration Rooms components:

- Fire Protection
- Structures Monitoring

3.5.2.1.9 Emergency Diesel Generator Buildings

Materials

The materials of construction for the Emergency Diesel Generator Buildings components are:

- Aluminum
- Carbon steel
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Galvanized steel
- Grout
- Stainless steel

Environments

The Emergency Diesel Generator Buildings components are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Fuel oil
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Emergency Diesel Generator Buildings components require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Emergency Diesel Generator Buildings components:

- Fire Protection
- Fuel Oil Chemistry
- Masonry Walls
- Structures Monitoring

3.5.2.1.10 Fire Rated Assemblies

Materials

The materials of construction for the fire rated assemblies components are:

- Carbon steel
- Cementitious fireproofing
- Cerafiber
- Flamemastic
- Galvanized steel
- Sealant
- Silicone elastomer
- Stainless steel
- Thermo-lag

Environments

The fire rated assemblies components are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor

Aging Effect Requirement Management

The following aging effects associated with the fire rated assemblies components require management:

- Cracking
- Hardening
- Loss of material
- Loss of strength
- Shrinkage

Aging Management Programs

The following aging management programs manage the aging effects for the fire rated assemblies components:

- Fire Protection

3.5.2.1.11 Intake Structure

Materials

The materials of construction for the Intake Structure components are:

- Carbon steel
- Concrete
- Galvanized steel
- Grout
- Stainless steel

Environments

The Intake Structure components are exposed to the following environments:

- Air – outdoor
- Groundwater/soil
- Water – flowing or standing

Aging Effect Requiring Management

The following aging effects associated with the Intake Structure components require management:

- Cracking
- Cumulative fatigue damage
- Deformation
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of strength
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Intake Structure components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Masonry Walls
- Structures Monitoring

3.5.2.1.12 Main Steam and Feedwater Platforms

Materials

The materials of construction for the Main Steam and Feedwater Platforms components are:

- Carbon steel
- Concrete
- Grout
- Galvanized steel

Environments

The Main Steam and Feedwater Platforms components are exposed to the following environments:

- Air – outdoor
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Main Steam and Feedwater Platforms components require management:

- Cracking
- Cumulative fatigue damage
- Deformation
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects the Main Steam and Feedwater Platforms components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Structures Monitoring

3.5.2.1.13 Plant Vent Stack

Materials

The materials of construction for the Plant Vent Stack components are:

- Carbon steel
- Concrete
- Galvanized steel
- Grout

Environments

The Plant Vent Stack components are exposed to the following environments:

- Air – outdoor

Aging Effect Requiring Management

The following aging effects associated with the Plant Vent Stack components require management:

- Loss of material
- Loss of preload
- Reduction in concrete anchor capacity

Aging Management Program

The following AMP manages the aging effects for the Plant Vent Stack components:

- Structures Monitoring

3.5.2.1.14 Polar Cranes

Materials

The materials of construction for the Polar Cranes components are:

- Carbon steel
- Stainless steel

Environments

The Polar Cranes components are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effect Requiring Management

The following aging effects associated with the Polar Cranes components require management:

- Cracking
- Cumulative fatigue damage
- Deformation
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Polar Cranes components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Structures Monitoring

3.5.2.1.15 Spent Fuel Storage and Handling

Materials

The materials of construction for the Spent Fuel Storage and Handling components are:

- Boral
- Carbon steel
- Concrete
- Grout
- Metamic
- Stainless steel

Environments

The Spent Fuel Storage and Handling components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Treated borated water
- Treated borated water >140°F

Aging Effect Requiring Management

The following aging effects associated with the Spent Fuel Storage and Handling components require management:

- Change in dimensions
- Cracking
- Cumulative fatigue damage
- Deformation
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Reduction in concrete anchor capacity
- Reduction of neutron-absorbing capacity

Aging Management Programs

The following AMPs manage the aging effects for Spent Fuel Storage and Handling components:

- Boric Acid Corrosion
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Monitoring of Neutron-Absorbing Materials other than Boraflex
- One-Time Inspection
- Structures Monitoring
- Water Chemistry

3.5.2.1.16 Turbine Building

Materials

The materials of construction for the Turbine Building components are:

- Aluminum
- Carbon steel
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Galvanized steel
- Grout

Environments

The Turbine Building components are exposed to the following environments:

- Air – indoor controlled
- Air – outdoor
- Soil

Aging Effect Requiring Management

The following aging effects associated with the Turbine Building require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Turbine Building components:

- Fire Protection
- Masonry Walls
- Structures Monitoring

3.5.2.1.17 Turbine Gantry Crane

Materials

The materials of construction for the Turbine Gantry Crane are:

- Aluminum
- Carbon steel
- Galvanized steel

Environments

The Turbine Gantry Crane components are exposed to the following environments:

- Air – outdoor

Aging Effect Requiring Management

The following aging effects associated with the Turbine Gantry Crane require management:

- Cracking
- Cumulative fatigue damage
- Deformation
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Turbine Gantry Crane components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Structures Monitoring

3.5.2.1.18 Yard Structures

Materials

The materials of construction for the Yard Structures are:

- Carbon steel
- Concrete
- Concrete block
- Galvanized steel
- Grout
- Stainless steel

Environments

The Yard Structures components are exposed to the following environments:

- Air – outdoor
- Air with borated water leakage

Aging Effect Requiring Management

The following aging effects associated with the Yard Structures require management:

- Cracking
- Cumulative fatigue damage
- Deformation
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Yard Structures components:

- Boric Acid Corrosion
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Masonry Walls
- Structures Monitoring

3.5.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the SLRA. For the Containment Structures, Structures and Component Supports those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

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, Section 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.*

Settlement is based directly on the physical properties of a structure's foundations material. During construction of PTN Units 3 and 4, the building site area was backfilled to the existing grade at elevation 18'-0" and compacted to 95 percent below the foundation level. In addition, the bedrock beneath the foundation is adequate with respect to the foundation conditions and is capable of supporting heavy loads. The most pronounced settlement is typically evidenced in the first several months after construction. The Structures Monitoring Program implementing procedure has monitored for indications of settlement, and there is no evidence of settlement OE at Turkey Point. Furthermore, the PTN Units 3 and 4 containment structures do not rely on a dewatering system for control of settlement and do not use porous concrete subfoundations. Therefore, cracking and distortion due to increased stress levels from settlement is not an aging effect for PTN Unit 3 and Unit 4 containment structures.

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, Section IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Section 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 the SRP-SLR).

The containment bulk ambient temperature during operation is between 50ºF and 120ºF. Operation with elevated normal bulk containment temperatures up to 125ºF for short periods of time during the summer months has also been evaluated. ACI 349, Code Requirements for Nuclear Safety Related Concrete Structures, specifies concrete temperature limits for normal operations or any other long-term period. Process piping carrying hot fluid (pipe temperature greater than 200ºF) routed through penetrations in the concrete walls by design does not result in temperatures exceeding 200ºF locally or result in a “hot spot” on the concrete surface. Therefore, reduction of strength and modulus due to elevated temperature is not an aging effect requiring management for the containment structure.

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, Section 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).*

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, Section 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).*

3. *Loss of material due to general, pitting, and crevice corrosion could occur in steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and interior surface of suppression chamber shell of Mark III containments. The existing program relies on ASME Code Section XI, Section 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).*

A plant-specific program, addressing loss of material in inaccessible areas of the containment, is not warranted for Turkey Point based on the following.

Design and construction of the reinforced-concrete containment structure at Turkey Point, including that in contact with the containment liner, is in accordance with ACI 318-63. The moisture barrier, at the junction where the liner is embedded in the concrete, is within the scope of the ASME Section XI, Subsection IWE AMP, which is supplemented by the 10 CFR Part 50, Appendix J AMP. Furthermore, the containment base slab concrete is monitored by the ASME Section XI, Subsection IWL AMP.

Turkey Point OE has not shown significant corrosion in inaccessible areas of the containment as described in Section B.2.3.30. Rather, OE confirms that borated water leaks or other water ponding on the liner are diverted to a sump. IWE inspections in

2010 found and corrected the Turkey Point Unit 3 containment liner plate which was corroded below minimum wall thickness at the floor to wall interface in the containment sump, with some perforations. The potential for degradation of the Unit 4 containment liner was also evaluated in 2010, and an acceptable wall thickness was confirmed. Degraded coatings and liner at higher elevations than the sump have also been addressed. The root cause of the Unit 3 containment liner degradation was failure of the coating system, which was not designed for periodic immersion service. Corrective Action to Prevent Recurrence (CAPR) consisted of application of a coating system suitable for immersion service on the liner plate in the lower region of both the Unit 3 and Unit 4 reactor pit areas. Program effectiveness of the ASME Section XI, Subsection IWE AMP is provided in Section B.2.3.30.

Turkey Point is a PWR and bullets 2 and 3 are not applicable.

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 the SRP-SLR

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for the containment structures is addressed in the Concrete Containment Tendon Prestress TLAA in Section 4.5 and is managed by the Concrete Containment Unbonded Tendon Prestress and ASME Section XI, Subsection IWL AMPs.

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.*

Cumulative fatigue damage for the Turkey Point liner and connections to penetration sleeves and hatches for the containment structures is addressed in the Containment Liner Plate and Penetrations Fatigue Analysis TLAA in Section 4.6.

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, Section 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.

The penetration sleeves (assemblies) penetrating the containment at Turkey Point are carbon steel. As such, SCC is not an applicable aging mechanism for penetration sleeves at Turkey Point. High-temperature piping systems that are stainless steel and penetrate the containment include dissimilar metal welds of the flued head of the steel penetration assembly to the outside of the pipe. These dissimilar metal welds are not considered susceptible to SCC. SCC requires a concentration of chloride contaminants, which are not normally present in significant quantities in containment, as well as high stress and temperatures greater than 140ºF. The containment bulk ambient temperature during operation is between 50ºF and 120ºF, and localized temperatures at penetrations are less than 200ºF by design. Furthermore, there has been no site OE of cracking of these dissimilar metal welds. Therefore, cracking of dissimilar metal welds for containment penetrations will be managed by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J AMPs, and no additional examinations are required.

3.5.2.2.1.7 Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw

Loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of PWR and BWR concrete containments. Further evaluation is recommended of this aging effect for plants located in moderate to severe weathering conditions.

The Turkey Point containment structures are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects to occur. Turkey Point is located in a “Negligible” weathering region per Figure 1 of ASTM C33-90, Location of Weathering Regions. Therefore, loss of material and cracking due to freeze-thaw are not aging effects requiring management for the below-grade inaccessible concrete areas of the Turkey Point containment structures.

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).

The reinforced-concrete containment structure at Turkey Point is designed and constructed in accordance with ACI 318-63 using materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-64, Florida Type II. Also, the cement contains no more than 0.60 percent by weight of total alkalies, which prevents harmful expansion due to alkali aggregate reaction. Concrete aggregates conform to the requirements of ASTM C-33-64 (fine and coarse aggregate) and conform to the requirements of ASTM C33, "Standard Specification of Concrete Aggregates." Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment and organic matter. Materials for concrete used in Turkey Point concrete structures and components (SCs) were specifically investigated, tested, and examined in accordance with pertinent ASTM standards at the time of construction. However, this testing may not fully conform to ASTM C295 specified in NUREG-2192; therefore, cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas for PTN Units 3 and 4 containment structure will be managed by the Turkey Point Structures Monitoring AMP. The Structures Monitoring AMP contains an enhancement to address reaction with aggregates.

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).

Each containment structure is a right-vertical, post-tensioned, reinforced-concrete cylinder with prestressed tendons in the vertical wall, a reinforced and post-tensioned concrete hemispherical domed roof, and a substantial base slab of reinforced concrete. The Turkey Point containment structures are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-64 150, Florida Type II. Concrete aggregates conform to the requirements of

ASTM C-33-64 (fine and coarse aggregate). During construction of PTN Units 3 and 4, the building site area was backfilled to the existing grade at elevation 18'-0", and the containment sub-structure is laying on compacted backfill. Therefore, PTN Units 3 and 4 structures, other than the intake or discharge structure, are not exposed to a water-flowing environment. In addition, NUREG-1522 described OE that Turkey Point tendon galleries were excessively humid, and floors and walls of the galleries were damaged by sustained water infiltration. The water infiltration in the below-grade structures resulted more from the improper drainage of the surface water rather than from the groundwater infiltration. The findings from the 1992 audit described in Appendix A of NUREG-1522 were evaluated in accordance with the corrective action program and determined to have no impact on intended functions. The OE from NUREG-1522 is addressed in the original Turkey Point license renewal application (LRA). There has been no recent Turkey Point evidence of leaching of water accumulation in below-grade accessible concrete areas of the containment structure that impact intended functions. Therefore, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation in below-grade inaccessible concrete areas is not an applicable aging effect for the inaccessible concrete of Turkey Point containment structures.

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.*

2. *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas for Groups 1–5 and 7–9 structures. Further evaluation is recommended of inaccessible areas of these Groups of structures to determine if a plant-specific AMP is required to manage this aging effect.*

3. *Cracking and distortion due to increased stress levels from settlement could occur in below-grade inaccessible concrete areas of structures for all Groups, and reduction in foundation strength, and cracking due to differential settlement and erosion of porous concrete sub foundations could occur in below-grade inaccessible concrete areas of Groups 1–3, 5–9 structures. The existing program relies on structure monitoring programs to manage these aging effects. Some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system, verification is recommended of the continued functionality of the dewatering system during the subsequent period of extended operation. No further evaluation is recommended if this activity is included in the scope of the applicant's structures monitoring program.*

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.*

Inaccessible areas at Turkey Point are addressed as follows:

1 Groups 2 and 9 structures are not applicable at Turkey Point. Groups 1, 3, 5, 7, and 8 structures at Turkey Point are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects to occur. Turkey Point is located in a “Negligible” weathering region per Figure 1 of ASTM C33, Location of Weathering Regions. Therefore, loss of material and cracking due to freeze-thaw are not aging effects requiring management for the below-grade inaccessible concrete areas of Turkey Point Group 1, 3, 5, 7, and 8 structures.

2. Groups 2 and 9 structures are not applicable at Turkey Point. Groups 1, 3-5, 7, and 8 structures at Turkey Point are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-64, Florida Type II. Also, the cement contains no more than 0.60 percent by weight of total alkalis, which prevents harmful expansion due to alkali aggregate reaction. Concrete aggregates conform to the requirements of ASTM C-33-64 (fine and coarse aggregate) and conform to the requirements of ASTM C33, “Standard Specification of Concrete Aggregates.” Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment and organic matter. Materials for concrete used in Turkey Point concrete SCs were specifically investigated, tested, and examined in accordance with pertinent ASTM standards at the time of construction. However, this testing may not fully conform to ASTM C295 specified in NUREG-2192, and, therefore, cracking due to expansion and reaction with aggregates, including alkali silicate reactions (ASR), is an applicable aging effect in below-grade inaccessible concrete areas for Turkey Point Groups 1, 3-5, 7, and 8 structures and will be managed by the Turkey Point Structures Monitoring AMP. The Structures Monitoring AMP contains an enhancement to address reaction with aggregates.

3. Groups 2 and 9 structures are not applicable at Turkey Point. Settlement is based directly on the physical properties of a structure’s foundations material. During construction of PTN Units 3 and 4, the building site area was backfilled to the existing grade at elevation 18’0’,’ and the Groups 1, 3, 5, 7, and 8 structures are founded on compacted backfill. The fill is compacted to 95 percent below the foundation level. The bedrock beneath the site is competent with respect to foundation conditions and is capable of supporting heavy loads. The most

pronounced settlement is typically evidenced in the first several months after construction. The Structures Monitoring Program implementing procedure for indications of settlement, and there is no evidence of settlement OE at Turkey Point. Additionally, the Turkey Point Groups 1, 3, 5, 7, and 8 structures do not rely on a dewatering system for control of settlement and do not use porous concrete subfoundations. Therefore, cracking and distortion due to increased stress levels from settlement is not an aging effect for Turkey Point Groups 1, 3-5, 7, and 8 structures.

4. Groups 2 and 9 structures are not applicable at Turkey Point. Groups 1, 3-5, 7, and 8 structures at Turkey Point are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-64 150, Florida Type II. Concrete aggregates conform to the requirements of ASTM C-33-64 (fine and coarse aggregate). Materials for concrete used in Turkey Point concrete SCs were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. The type and size of aggregate, slump, cement and additives have been established to produce durable concrete in accordance with ACI. Cracking is controlled through proper arrangement and distribution of reinforcing steel. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R. During construction of PTN Units 3 and 4, the building site area was backfilled to the existing grade at elevation 18’-0”, and the containment sub-structure is laying on compacted backfill. Therefore, Turkey Point Groups 1, 3-5, 7, and 8 structures are not exposed to a water-flowing environment. In addition, NUREG-1522 described that Turkey Point tendon galleries were excessively humid, and floors and walls of the galleries were damaged by sustained water infiltration. The water infiltration in the below-grade structures resulted more from the improper drainage of the surface water rather than from the groundwater infiltration. The findings from the 1992 audit described in Appendix A of NUREG-1522 were evaluated in accordance with the corrective action program and determined to have no impact on intended functions. The OE from NUREG-1522 is addressed in the original Turkey Point license renewal application (LRA). There has been no recent Turkey Point evidence of leaching or water accumulation in below-grade accessible concrete areas of the Turkey Point Groups 1, 3–5, 7, and 8 structures that impact intended functions. Therefore, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation in below-grade inaccessible concrete areas, are not applicable aging effects for the inaccessible Turkey Point Groups 1, 3–5, 7, and 8 concrete 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).

During normal operation, structures at Turkey Point are maintained below a bulk average temperature of 120ºF by plant cooling systems. ACI 349, Code Requirements for Nuclear Safety Related Concrete Structures, specifies concrete temperature limits for normal operations or any other long-term period. Process piping carrying hot fluid (pipe temperature greater than 200ºF) routed through penetrations in the concrete walls by design does not result in temperatures exceeding 200ºF locally or result in a “hot spot” on the concrete surface. The penetration configuration includes guard pipes and insulation of the process piping to minimize heat transfer from the process pipe to the exterior environment surrounding the process piping. Therefore, reduction of strength and modulus due to elevated temperature is not an aging effect requiring management for Turkey Point Group 1,3–5 structures.

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

Further evaluation is recommended for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL-SLR Report, AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” or Federal Energy Regulatory Commission (FERC)/U.S. Army Corp of Engineers dam inspection and maintenance procedures.

1. *Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is recommended of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions.*

2. *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas of Group 6 structures. Further evaluation is*

recommended to determine if a plant-specific AMP is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

3. *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).*

Further evaluation of above items is respectively addressed below:

1. The Group 6 structures at Turkey Point subject to air-outdoor environment are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects to occur. Turkey Point is located in a “Negligible” weathering region per Figure 1 of ASTM C33, Location of Weathering Regions. Therefore, loss of material and cracking due to freeze-thaw are not aging effects requiring management for the below-grade inaccessible concrete areas of Turkey Point Group 6 structures.

2. The Group 6 structures at Turkey Point are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-64 150, Florida Type II. Also, the cement contains no more than 0.60 percent by weight of total alkalis, which prevents harmful expansion due to alkali aggregate reaction. Concrete aggregates conform to the requirements of ASTM C-33-64 (fine and coarse aggregate) and conform to the requirements of ASTM C33, “Standard Specification of Concrete Aggregates.” Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment and organic matter. Materials for concrete used in Turkey Point concrete SCs were specifically investigated, tested, and examined in accordance with pertinent ASTM standards at the time of construction. However, this testing may not fully conform to ASTM C295 specified in NUREG-2192, and, therefore, cracking due to expansion and reaction with aggregates is an applicable aging effect in below-grade inaccessible concrete areas for Turkey Point Group 6 structures and will be managed by the Turkey Point Inspection of Water-Control Structures Associated with Nuclear Power Plants.

3. The Group 6 Structures at Turkey Point are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-64 150, Florida Type II. Concrete aggregates conform to the requirements of ASTM C-33-64 (fine and coarse aggregate). Materials for concrete used in Turkey Point concrete SCs were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. The type and size of aggregate,

slump, cement and additives have been established to produce durable concrete in accordance with ACI. Cracking is controlled through proper arrangement and distribution of reinforcing steel. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R. The below-grade inaccessible concrete areas of Group 6 concrete structures at Turkey Point are exposed to groundwater that is considered equivalent to a flowing water environment. From comparison with the chloride level for seawater, the groundwater/soil at Turkey Point is considered as aggressive since the chloride level is much greater than 500 ppm due to seawater. The criteria for plants to determine aggressive groundwater/soil is as follows: pH < 5.5, chlorides > 500 ppm, or sulfates > 1,500 ppm.

Therefore, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation in below-grade inaccessible concrete areas, are applicable aging effects for the inaccessible concrete of Turkey Point Group 6 concrete structures. The Turkey Point Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP manages increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation in below-grade inaccessible concrete areas of Turkey Point Group 6 concrete 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 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members; welds; bolted connections; or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, "ASME Section XI, Section 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.*

Cracking due to SCC and loss of material due to pitting and crevice corrosion are applicable aging effects in stainless steel and aluminum alloy support members, welds, bolted connections, or support anchorages to building structures exposed to any air, condensation, or underground environment where the presence of sufficient halides (e.g., chlorides) and moisture is possible. Since seawater has a high chloride level, cracking due to SCC and loss of material due to pitting and crevice corrosion is an applicable aging effect at Turkey Point for stainless steel and aluminum alloys and is monitored with the Turkey Point Structures Monitoring AMP.

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.

Since CLB fatigue analysis for cumulative fatigue damage due to time-dependent fatigue, cyclic loading, or cyclical displacement of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports does not exist at Turkey Point, it is not an aging effect requiring management at Turkey Point. Cumulative fatigue damage due to cyclic loading is an applicable aging effect for cranes (overhead heavy and light load (related to refueling) handling systems) at Turkey Point and is addressed in the Crane Load Cycle Limit TLAA in Section 4.7.6.

3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

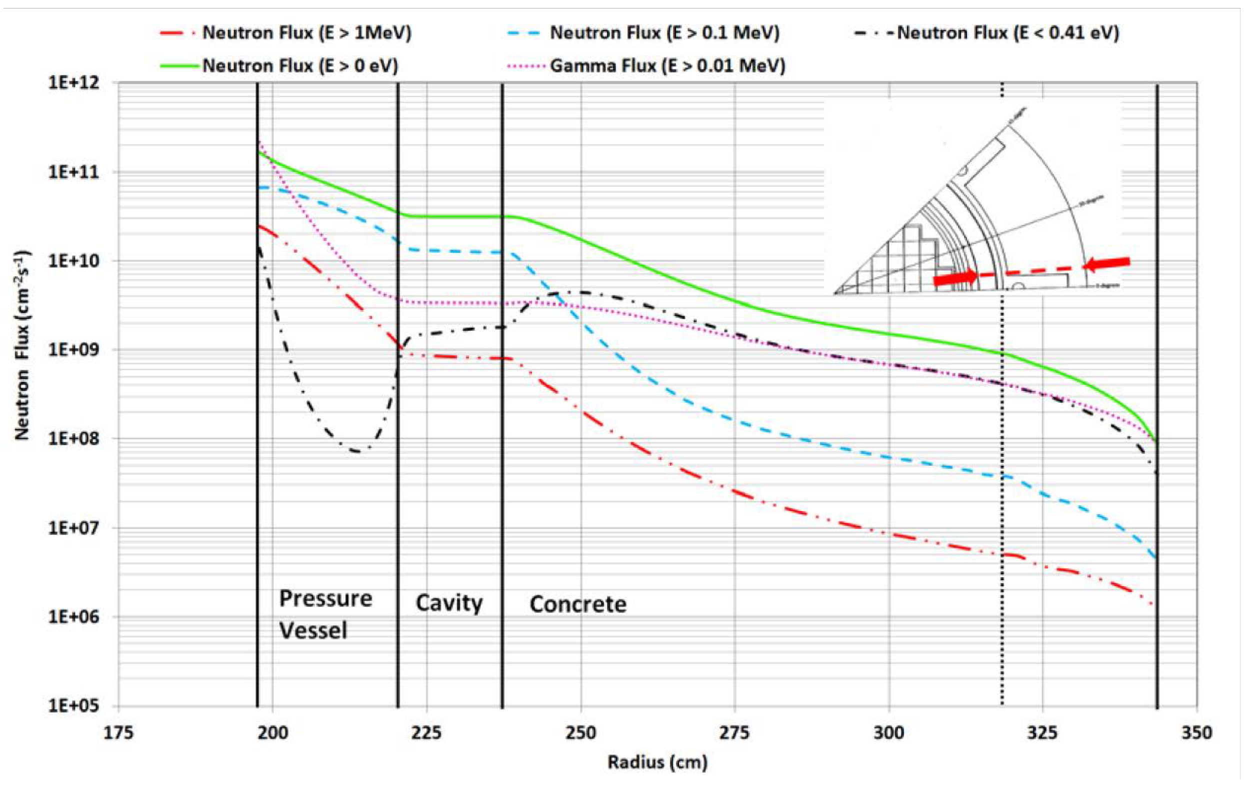
Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the sacrificial shield wall, 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.*

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)

Conservative calculations performed to determine the projected peak neutron fluence and gamma dose within the PTN Unit 3 and Unit 4 reactor cavity for 80 years of plant operation have shown they are above the radiation exposure thresholds of 1×10^{19} n/cm^2 and 1×10^{10} rad, respectively, noted above for degradation of concrete (reduction of strength or mechanical properties) at the end of the SPEO. The evaluation and supporting calculation summaries of the irradiation effects on the primary shield wall, including embedded reinforcements, and reactor vessel support structures are described below and indicate the primary shield wall and RV supports will be able to perform their component intended functions for the SPEO.

The peak 80-year fast fluence of 1.08 × 10^{20} n/cm^2 (E > 1.0 MeV) at the interior surface of the reactor vessel base metal at the limiting beltline location is reported in SLRA Table 4.2.1-1. This fast fluence is projected to be below the threshold at the inner surface of the primary shield wall based on conservative attenuation estimates. To account for thermal fluence (E > 0.1 MeV) in the cavity, the PTN environmental qualification (EQ) document package for the (ex-core) neutron flux monitoring system was utilized.

The conservative 40-year EQ neutron flux for these detector cables, in the reactor cavity, is 4.27 x 10^{10} n/cm^2/sec. Neutron flux data as a function of distance from the core is presented in the figure (shown below) of the "Characterization of Radiation Fields in Biological Shields of Nuclear Power Plants for Assessing Concrete Degradation", I. Remec, et al, that was developed by the Oak Ridge National Laboratory (ORNL) and presented at the International Symposium or Reactor Dosimetry (Volume 106, 2016, Article 02002, published February 3, 2016, later referred to as ISRD 15). The data presented in the figure is based on a Westinghouse 3-loop design. The relative configuration of the RV and concrete shield wall depicted in that figure are approximately equivalent to the RV and primary shield wall configuration at PTN.



Characterization of Radiation Fields in Biological Shields of Nuclear Power Plants for Assessing Concrete Degradation, I. Remec, et al, ORNL

The PTN EQ neutron flux and the neutron flux (E > 0.1 MeV) at the inner edge of the reactor cavity concrete presented in the above ORNL figure were used to establish a multiplier to be applied to the ORNL flux in the concrete to calculate the PTN neutron flux as a function of distance through the shield wall as shown in the following table.

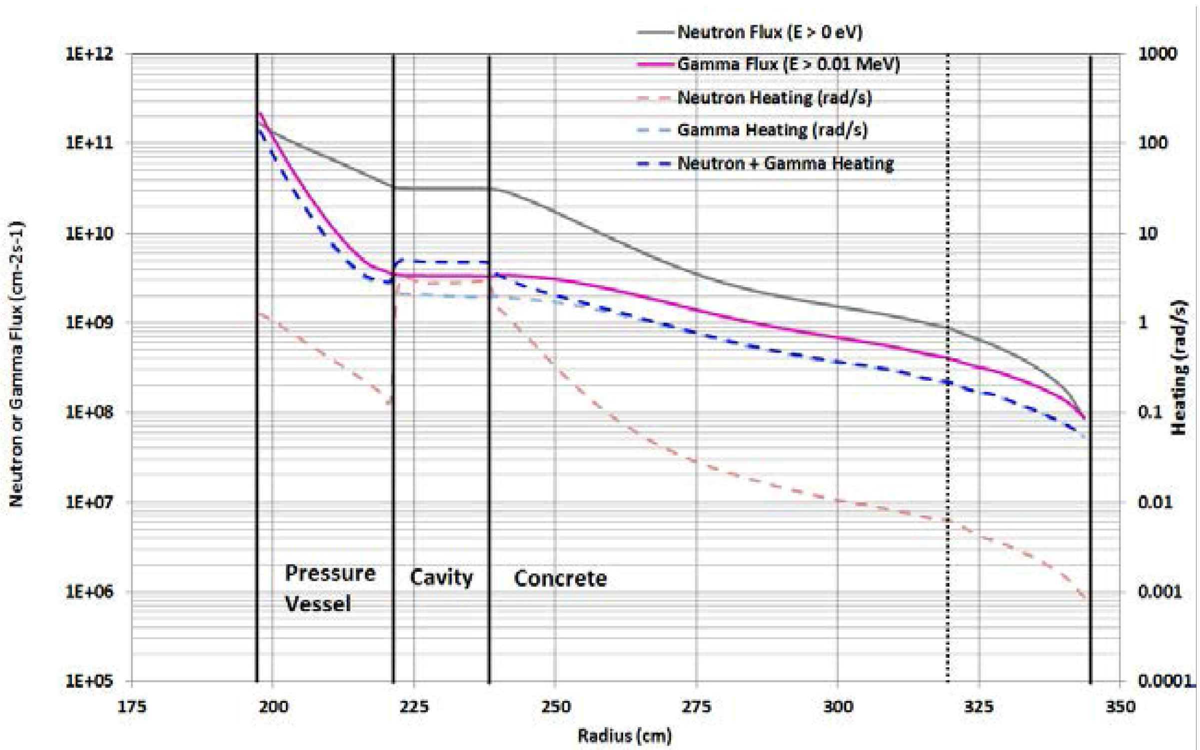
Neutron flux as a function of distance through the shield wall		
Radius (cm)	**ORNL Figure Flux (n/cm^2- sec)**	**PTN Flux (n/cm^2-sec)**
238	1.10E+10	4.27E+10
250	2.00E+09	7.76E+09
255	1.00E+09	3.88E+09
260	5.00E+08	1.94E+09
266	3.00E+08	1.16E+09
272	2.00E+08	7.76E+08
275	1.70E+08	6.60E+08

The cumulative 80 year end-of-life (EOL) neutron fluence as a function of distance through the shield wall was calculated based on the above. The neutron fluxes as a function of distance through the shield wall were converted to cumulative fluences by converting seconds to years and determining the 80-year fluences based on a capacity factor of 90 percent, 72 effective fuel power years (EFPY) in 80 calendar years. Calculated PTN fluences as a function of depth into the concrete are presented in the following table that also includes conversion of the above radius values (cm) to inches into the concrete shield, as well as linear interpolation to determine the depth beyond which the wall is not expected to be damaged due to neutron flux.

PTN Neutron fluence as a function of distance through the shield wall	
Depth (inches)	**80-Year Fluence (n/cm^2)**
0	9.70E+19
4.7	1.76E+19
6.4*	1.00E+19
6.7	8.82E+18
8.7	4.41E+18
11.0	2.65E+18
13.4	1.76E+18
14.6	1.50E+18

* This value is interpolated using fluence data at 4.7 and 6.7 inches

Additional work related to that of the above "Characterization of Radiation Fields in Biological Shields of Nuclear Power Plants for Assessing Concrete Degradation" (ISRD 15) is provided in "Radiation Damage in Reactor Cavity Concrete," T.M. Rosseel, et al, (Proceedings of Fontevraud 8, Contribution of Materials Investigations and Operating Experience to LWR Safety, Performance and Reliability, September 2014) that was also developed by the ORNL relative to the contribution of materials investigations and operating experience relative to light water reactor (LWR) safety, performance and reliability. Data regarding the gamma doses in a concrete shield wall is provided as a function of distance as shown in the figure below.



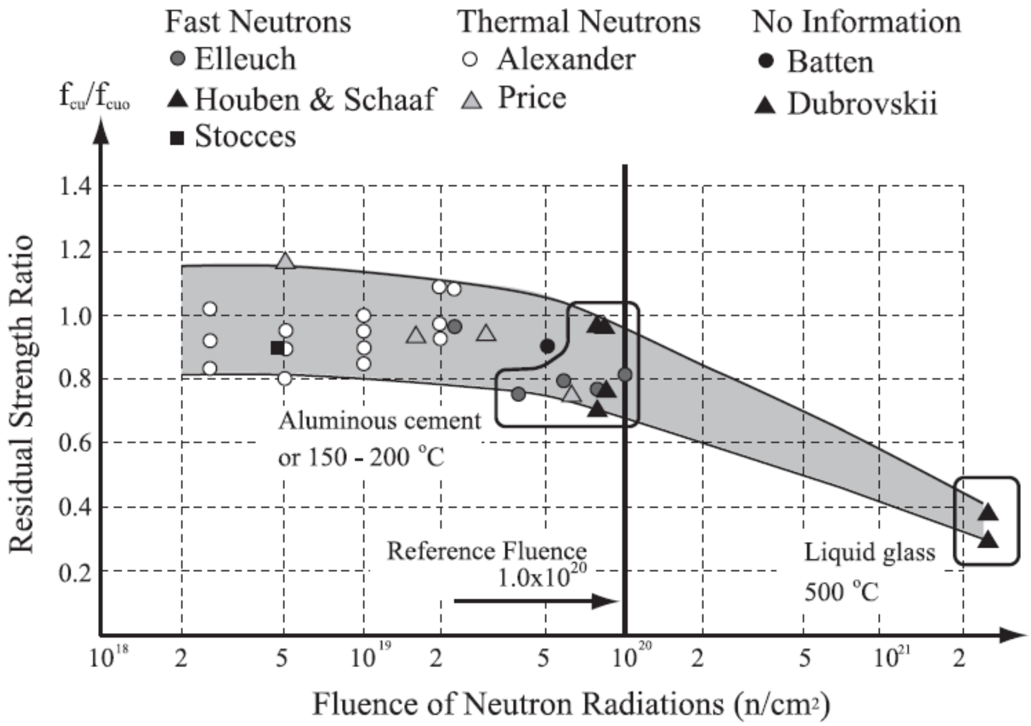
Radiation Damage in Reactor Cavity Concrete,T.M. Rosseel, et al, Proceedings of Fontevraud 8, Contribution of Materials Investigations and Operating Experience to LWR Safety, Performance and Reliability, September 2014, ORNL

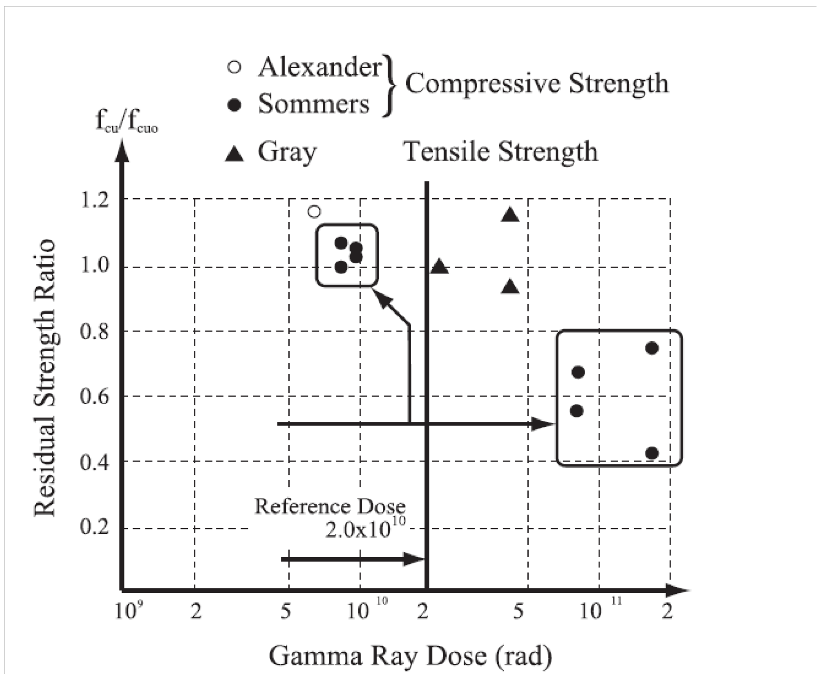
The conservative 40-year EQ integrated gamma dose for the ex-core neutron detector cables in the reactor cavity is 1.7 x 10^{10} rad, which equates to 3.4 × 10^{10} rad for 80 years. Similar to the neutron fluence addressed above, the gamma (rad/sec) data as a function of distance was used to calculate the gamma dose at various points in the shield wall. The extracted data and equivalent PTN values, developed using the ratio of 2 rad/sec to the PTN integrated 80-year reactor cavity dose of 3.4 × 10^{10} rad, are summarized in the table below. Interpolation was again used to determine the depth beyond which degradation of the concrete is not expected due to gamma dose.

Gamma dose as a function of distance through the shield wall			
Radius (cm)(1)	**Depth (inches)**	**"Radiation Damage in Reactor Cavity Concrete" Dose (rad/sec)(1)**	**PTN Integrated Dose (rad)**
238	0	2	3.40×10^{10}
250	4.7	1.9	3.23×10^{10}
267	11.4	1	1.70×10^{10}
275	14.6	0.75	1.28×10^{10}
281	16.9	0.6	1.02×10^{10}
281.7**(2)**	17.2**(2)**	n/a	1.00×10^{10}
287	19.3	0.5	8.50×10^{9}
294	22.0	0.4	6.80×10^{9}
1. Extracted from ORNL figure. 2. These values interpolated using data points above and below.			

The first 17 inches of the primary shield wall across from the effective height of the active fuel in the RV are projected to be exposed to gamma radiation above the conservative threshold. Integrated EQ doses are typically based on a conservative assumption of 1 percent failed fuel. As such, the thickness of the primary shield wall that is exposed to gamma radiation above the threshold is expected to be less.

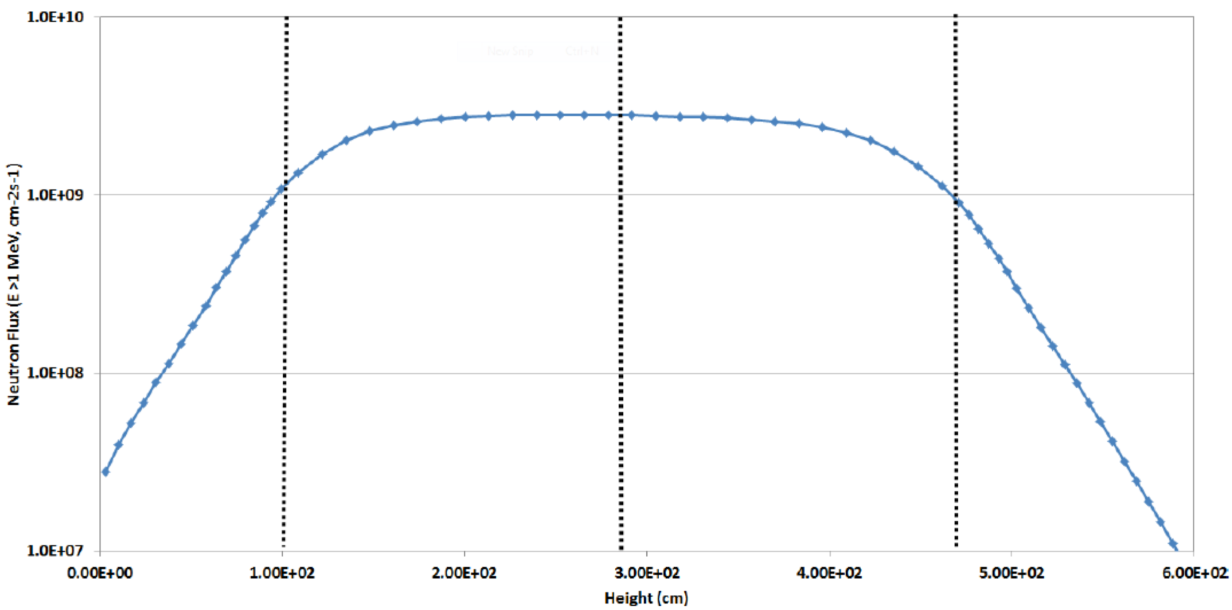
As indicated above, the concrete shield is conservatively projected to incur neutron fluences and gamma doses in excess of the threshold values above, and as a result, some reduction in compressive strength could occur. Estimates of the onset of damage and residual concrete strength were made in American Concrete Institute (ACI) SP 55-10 ("The Effects of Nuclear Radiation on the Mechanical Properties of Concrete," H.K. Hilsdorf, et al, ACI, 1978), a commonly referenced industry document and a source of the neutron and gamma limits established in NUREG-2192. The figures from ACI SP 55-10 that present the residual strength of concrete as a function of neutron fluence or gamma dose are reformatted in IAEA-CN-194-093, "Development of System for Evaluating Concrete Strength Deterioration Due to Radiation and Resultant Heat," I. Maruyama, et al. This data is presented in the figures below:





IAEA-CN-194-093, "Development of System for Evaluating Concrete Strength Deterioration Due to Radiation and Resultant Heat," I. Maruyama, et al.

As shown in the figures above, from IAEA-CN-194-093, the concrete retains a substantial portion of its compressive strength for the radiation values covered in this report, and is shown to retain 60% or more of its compressive strength for neutron fluence and gamma dose values well above the values even on the inner surface of the concrete shield wall. Note that the ORNL radiation evaluations discussed above are based on the neutron and gamma fluxes that occur along the axial centerline of the active fuel region. As such, these are expected to be peak values. Lower values are expected along the wall at points further away from the axial centerline of the active fuel region, as shown in the figure below (I. Remec, Radiation Environment in Concrete Biological Shields of Nuclear Power Plants (Link: https://lwrs.inl.gov/Materials%20Aging%20and%20Degradation/ProgressReportRadEffectsinConcreteBioShield_Final.pdf)). Thus, no gamma radiation or neutron fluence values above the concrete degradation thresholds of 1×10^{10} rad and 1×10^{19} n/cm^2, respectively, are expected above and below the active fuel region heights along the concrete shield wall.



The primary shield wall at PTN Unit 3 and Unit 4 is 7'-0" (84") thick, as described in UFSAR Sections 5.1.8.1 and 5.1.8.3, and is a part of the RV support structure, as described in UFSAR Section 5.1.9.3. The RV supports consist of six (6) individual supports, one of which is placed under each of the three hot leg and three cold leg Reactor Coolant System pipe nozzles. A majority of each RV support is embedded in the primary shield wall. The primary shield wall also provides structural support for a portion of the containment internal structure that includes the slab at El. 58'-0", walls above 32'-0", radial walls above 32'- 0" and the slab at 30'-6". The primary shield wall is 21 feet in height, surrounds the RV (that is approximately 14.5 feet in diameter), and extends from just below the matting flange with the RV head at the refueling canal floor down to where it connects with the containment building foundation. The wall is a donut shaped reinforced concrete (3000 psi) structure that has an inside diameter of 19 feet and an outside octagonal sided wall with a minimum outside diameter of 33 feet.

As noted above, concrete depths required to reduce the neutron fluence and gamma dose levels to below the threshold values are 6.4 inches and 17.2 inches, respectively. Based on the figures above, a worst case reduction in the strength of 40% could occur along the circumference of the inner face of the primary shield wall up to 17 inches in depth at the active fuel core midline elevation, with the effects decreasing with concrete depth and vertical distance from the fuel centerline to the ends of the active fuel core. No radiation levels in excess of the threshold values are expected above and below the active fuel region elevation along the interior face of the primary shield wall. Reinforcing steel (rebar) across from the area encompassing the effective height of active fuel is located a distance of 19 inches from the inner edge of the wall, and is not affected by increased neutron fluence or gamma dose.

In order to bound the reduction in strength described above, an additional calculation was performed based on the removal of the primary shield wall to a depth of 17 inches. A review of the current PTN primary shield wall calculation indicates that the wall total compressive surface area is 89,500 in^2. By removing the inner 17 inches of wall, the wall compressive surface area is reduced to 76,382 in^2 or a 15% reduction. The allowable compressive load on the reduced area can be calculated as 0.85 x 3000 psi x 76,382 in^2 = 194,774 kips. The total dead and live load acting on the wall is 7,509 kips, or approximately 4% of its capacity for the reduced area. Per the primary shield wall calculation, the compressive stresses are low and the highest stresses are at the outer edge of the wall due to overturning moments from seismic and unsymmetrical loads. Since the reinforcing steel is only exposed to radiation levels below the NUREG-2192 threshold values and thus not affected by increased radiation levels, the resistance of the wall to moments is not significantly affected by the loss of the inner concrete area. Stresses due to torsion or bending moments are seen at the outer edge of the wall as a function of its shape where the neutron fluence and gamma dose levels are well below the NUREG-2192 threshold values.

In addition, there has been no site-specific OE relative to radiation effects on concrete intended functions. Also, the Turkey Point reactor vessels are nozzle supported as described above, and there is no support pedestal. The RV supports are structural steel with most of the support embedded in the primary shield wall. The RV supports are not exposed to the same levels of neutron and gamma radiation as the horizontal exposed supports are at the RV nozzle level, above the effective height of the active fuel, and the embedded portions are shielded by the concrete wall. Furthermore, irradiation embrittlement of RV supports has been addressed as a generic safety issue, GSI-15, and resolved based on a risk-informed evaluation. Lastly, the SLR update of the EQ document package for approach and treatment of issues confirms that 80-year normal operation radiation exposure is below the conservative degradation thresholds. The total integrated gamma dose received by equipment inside containment (excluding equipment located inside the reactor cavity) during 80 years of normal operation is 5.02×10^7 rads. Neutron fluence from the reactor vessel/core will attenuate to well below the conservative fluence threshold for degradation in or before the 84 inch thickness of the primary shield wall and is, therefore, not a concern outside the reactor cavity, consistent with the existing CLB.

Based on the above, a plant-specific program to manage the effects of concrete irradiation is not expected to be necessary to ensure the components perform their intended function consistent with the CLB through the subsequent period of extended operation. However, FPL will continue to follow the on-going industry efforts that are clarifying the effects of irradiation of concrete and corresponding aging management recommendations, and will:

a. ensure their applicability to the PTN Unit 3 and Unit 4 primary shield wall and associated reactor vessel supports;

b. update design calculations, as appropriate; and

c. develop an informed plant-specific program, if needed.

Although not used as design inputs, some recent industry documents addressing concrete condition with prolonged neutron and gamma irradiation include:

- 2012 - Effects of Radiation on Concrete: A Literature Survey and Path Forward, 1022584;

- 2014 - Expected Condition of Reactor Cavity Concrete After 80 Years of Radiation Exposure, 2014, 3002002676;

- 2015 - Field, K.G., Y. Le Pape, and I. Remec. "Perspectives on Radiation Effects in Concrete for Nuclear Power Plants-Part I: Quantification of Radiation Exposure and Radiation Effects." Nuclear Engineering and Design. Vol 282. pp 126-143. February 2015;

- 2016 - Structural Model of PWR Concrete Reactor Pressure Supports - Revision 1 Effects of Chronic Radiation Exposure on Margin, 3002007347.

3.5.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Containments, Structures and Component Supports components:

- Section 4.5, Concrete Containment Tendon Prestress
- Section 4.6, Containment Liner Plate and Penetrations Fatigue Analysis Fatigue
- Section 4.7, Other Plant-Specific Time-Limited Aging Analysis

3.5.3 Conclusion

The structural components and commodities subject to AMR have been identified in accordance with the criteria of 10 CFR 54.4. The AMPs selected to manage the effects of aging on structural components and commodities are identified in Section 3.5.2 above. A description of the AMPs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the structural components and commodities will be managed such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the SPEO.

Table 3.5-1
Summary of Aging Management Evaluations
for the Containment, Structures, and Component Supports

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. Turkey Point does not rely upon a de-watering system to control settlement. Further evaluation is documented in Section 3.5.2.2.1.1.
3.5-1, 002	Concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. Turkey Point does not rely upon a de-watering system to control settlement. Further evaluation is documented in Section 3.5.2.2.1.1.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 003	Concrete: dome; wall; basemat; ring girders; buttresses, concrete: containment; wall; basemat, concrete: basemat, concrete fill-in annulus	Reduction of strength and modulus of elasticity due to elevated temperature (>150°F general; >200°F local)	Plant-specific AMP	Yes (SRP-SLR Section 3.5.2.2.1.2)	Not applicable. The containment structure bulk ambient temperature during operation is between 50ºF and 120ºF. Further evaluation is documented in Section 3.5.2.2.1.2.
3.5-1, 004	This line item only applies to BWRs.				
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, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191. Further evaluation is documented in Section 3.5.2.2.1.3.
3.5-1, 006	This line item only applies to BWRs.				
3.5-1, 007	This line item only applies to BWRs.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 (SRP-SLR Section 3.5.2.2.1.4)	Concrete containment tendon prestress TLAA is addressed in Section 4.5. Further evaluation is documented in Section 3.5.2.2.1.4.
3.5-1, 009	Metal liner, metal plate, personnel airlock, equipment hatch, control rod drive (CRD) hatch, penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell; unbraced downcomers, steel elements: vent header; downcomers	Cumulative fatigue damage due to cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.6, "Containment Liner Plate and Penetration Fatigue Analysis"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Containment liner plate fatigue analysis is addressed in Section 4.6. Further evaluation is documented in Section 3.5.2.2.1.5.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.6)	Consistent with NUREG-2191. The Turkey Point ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J AMPs will be used to manage cracking of dissimilar medal welds exposed to uncontrolled indoor air and outdoor air environments. Further evaluation is documented in Section 3.5.2.2.1.6.
3.5-1, 011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific AMP	Yes (SRP-SLR Section 3.5.2.2.1.7)	Not applicable. Turkey Point containment structures are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects. Further evaluation is documented in Section 3.5.2.2.1.7.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 AMP	Yes (SRP-SLR Section 3.5.2.2.1.8)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP is the plant-specific AMP that will be used to manage cracking for inaccessible concrete with a focus on portions exposed to groundwater/soil environments as leading indicators. Further evaluation is documented in Section 3.5.2.2.1.8.
3.5-1, 013	There is no 3.5-1, 013 in NUREG-2192.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 014	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific AMP	Yes (SRP-SLR Section 3.5.2.2.1.9)	Not applicable. The Turkey Point containment structures are not exposed to water-flowing environments or water accumulation in accessible areas that impacts intended functions. Further evaluation is documented in Section 3.5.2.2.1.9.
3.5-1, 015	There is no 3.5-1, 015 in NUREG-2192.				
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, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL AMP will be used to manage increase in porosity and permeability, cracking, and loss of material (spalling, scaling) for accessible concrete exposed to uncontrolled indoor air and outdoor air.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 017	There is no 3.5-1, 017 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, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Not applicable. Containment structures at Turkey Point are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects. Further evaluation is documented in Section 3.5.2.2.1.7.
3.5-1, 019	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment; concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	AMP XI.S2, "ASME Section XI, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL AMP will be used to manage cracking due to accessible concrete exposed to uncontrolled indoor air, outdoor air, and groundwater/soil environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 020	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S2, "ASME Section XI, Section IWL"	No	Not applicable. The Turkey Point containment structures are not exposed to water-flowing environments.
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, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL AMP will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) for accessible concrete exposed to uncontrolled indoor air and outdoor air environments.
3.5-1, 022	There is no 3.5-1, 022 in NUREG-2192.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL AMP and Structures Monitoring AMP will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) for inaccessible concrete exposed to uncontrolled indoor air, outdoor air, and groundwater/soil environments

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 024	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): dome; wall; basemat	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, "ASME Section XI, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception for the Structures Monitoring AMP. The ASME Section XI, Subsection IWL AMP supplemented by the Structures Monitoring AMP will be used to manage increase in porosity and permeability, cracking, and loss of material (spalling, scaling) in inaccessible concrete areas exposed to uncontrolled indoor air, outdoor air, and groundwater/soil environments.
3.5-1, 025	There is no 3.5-1, 025 in NUREG-2192.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP will be used to manage loss of sealing for the sealant associated with the liner plate moisture barrier exposed to an uncontrolled indoor air environment.
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, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable. CLB fatigue analysis is described in Section 4.6.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP and 10 CFR Part 50, Appendix J AMP will be used to manage loss of material of the Containment Structure hatches and accessories exposed to uncontrolled indoor air and outdoor air environments.
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, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP and 10 CFR Part 50, Appendix J AMP will be used to manage loss of leak tightness due to mechanical wear of the Containment Structure hatches and accessories exposed to uncontrolled indoor air and outdoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP and 10 CFR Part 50, Appendix J AMP will be used to manage loss of preload due to self-loosening of the Containment Structure pressure-retaining bolting exposed to uncontrolled indoor air and outdoor air environments.
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, Section IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP will be used to manage loss of material of steel exposed to uncontrolled indoor air and outdoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWL"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL AMP will be used to manage loss of material of the steel tendons and anchorage components associated with the post tensioning system exposed to uncontrolled indoor air and outdoor air environments.
3.5-1, 033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S4, "10 CFR Part 50, Appendix J "	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP will be used to manage loss of sealing of seals associated with the Containment Structure seals and gaskets exposed to uncontrolled indoor air and outdoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 034	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coating Monitoring and Maintenance AMP will be used to manage loss of coating integrity of the Containment Structure internal Service Level 1 coatings.
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, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J AMPs will be used to manage loss of material of accessible steel elements exposed to uncontrolled indoor air and outdoor air environments. Further evaluation is documented in Section 3.5.2.2.1.3.
3.5-1, 036	This line item only applies to BWRs.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 037	This line item only applies to BWRs.				
3.5-1, 038	This line item only applies to BWRs.				
3.5-1, 039	This line item only applies to BWRs.				
3.5-1, 040	This line item only applies to BWRs.				
3.5-1, 041	This line item only applies to BWRs.				
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 AMP	Yes (SRP-SLR Section 3.5.2.2.2.1 Item 1)	Not applicable. Group 1-3, 5, 7- 9 structures at Turkey Point are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects. Further evaluation is documented in Section 3.5.2.2.2.1 Item 1.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 AMP	Yes (SRP-SLR Section 3.5.2.2.2.1 Item 2)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP is the plant-specific AMP that will be used to manage cracking of inaccessible concrete with a focus on portions exposed to groundwater/soil as leading indicators. Further evaluation is documented in Section 3.5.2.2.2.1 Item 2.
3.5-1, 044	All Groups: concrete: all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1 Item 3)	Not applicable. Turkey Point does not rely upon a de-watering system to control settlement. Further evaluation is documented in Section 3.5.2.2.2.1 Item 3.
3.5-1, 045	There is no 3.5-1, 045 in NUREG-2192				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 046	Groups 1-3, 5-9: concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1 Item 3)	Not applicable. Turkey Point does not rely upon a de-watering system to control settlement. Further evaluation is documented in Section 3.5.2.2.2.1 Item 3.
3.5-1, 047	Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific AMP	Yes (SRP-SLR Section 3.5.2.2.2.1 Item 4)	Not applicable. Turkey Point Groups 1-5, 7-9 structures are not exposed to water-flowing environments or water accumulation in accessible areas that impacts intended functions. Further evaluation is documented in Section 3.5.2.2.2.1 Item 4.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 048	Groups 1-5: concrete: all	Reduction of strength and modulus due to elevated temperature (>150°F general; >200°F local)	Plant-specific AMP	Yes (SRP-SLR Section 3.5.2.2.2.2)	Not applicable. During normal operation, structures at Turkey Point are maintained below a bulk average temperatures of 120ºF. Process piping carrying hot fluid (pipe temperature greater than 200ºF) routed through penetrations in the concrete walls by design do not result in temperatures exceeding 200ºF. Further evaluation is documented in Section 3.5.2.2.2.2.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 049	Group 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific AMP	Yes (SRP-SLR Section 3.5.2.2.2.3 Item 1)	Not applicable. Turkey Point Group 6 structures at Turkey Point are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects. Further evaluation is documented in Section 3.5.2.2.2.3, Item 1.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 AMP	Yes (SRP-SLR Section 3.5.2.2.2.3 Item 2)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage cracking for inaccessible concrete for Group 6 structures exposed to outdoor air, water – flowing or standing, and groundwater/soil environments. Further evaluation is documented in Section 3.5.2.2.2.3, Item 2.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 AMP	Yes (SRP-SLR Section 3.5.2.2.2.3 Item 3)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage increase in porosity and permeability and loss of strength for inaccessible concrete for Group 6 structures exposed to water – flowing environments. Further evaluation is documented in Section 3.5.2.2.2.3, Item 3.
3.5-1, 052	Groups 7, 8 - steel components: tank liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.5.2.2.2.4)	Not applicable. There are no stainless steel tank liners in the Structures and Component Supports group. Further evaluation is documented in Section 3.5.2.2.2.4.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 (SRP-SLR Section 3.5.2.2.2.5)	Not applicable. CLB fatigue analysis does not exist. Further evaluation is documented in Section 3.5.2.2.2.5.
3.5-1, 054	All groups except 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage cracking of accessible concrete exposed to uncontrolled indoor air, controlled indoor air, outdoor air, and groundwater/soil environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 055	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage reduction in concrete anchor capacity for accessible concrete exposed to uncontrolled indoor air, controlled indoor air, and outdoor air environments.
3.5-1, 056	Concrete: exterior above- and below-grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be used to manage loss of material of concrete exposed to water – flowing environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP will be used to manage loss of mechanical function for supports exposed to an uncontrolled indoor air environment.
3.5-1, 058	Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be used to manage loss of material, loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage for earthen water-control structures exposed to outdoor air and water - flowing or standing environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 AMP will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) of accessible concrete exposed to outdoor air, groundwater/soil, and water-flowing or standing environments.
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	Not applicable. Turkey Point Group 6 structures are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 AMP will be used to manage increase in porosity and permeability and loss of strength for accessible concrete exposed to outdoor air, groundwater/ soil, and water-flowing or standing environments.
3.5-1, 062	Group 6: Wooden Piles; sheeting	Loss of material; change in material properties due to weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable. There are no wooden piles or sheeting in the Structures and Component Supports group.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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	Not applicable. Turkey Point Groups 1-3, 5, 7-9 structures are not exposed to water-flowing environments.
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	Not applicable. Turkey Point Groups 1-3, 5, 7-9 structures at Turkey Point are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 065	Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) for accessible and inaccessible concrete exposed to outdoor air and groundwater/soil environments.
3.5-1, 066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) for accessible concrete exposed to uncontrolled indoor air, controlled indoor air, and outdoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 067	Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1-3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage increase in porosity and permeability, cracking, loss of material (spalling, scaling) for inaccessible concrete for uncontrolled and controlled indoor air, outdoor air, and groundwater/soil environments
3.5-1, 068	High-strength steel structural bolting	Cracking due to SCC	AMP XI.S3, "ASME Section XI, Section IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP will be used to manage cracking for high strength steel bolting exposed to an uncontrolled indoor air environment.
3.5-1, 069	There is no 3.5-1, 069 in NUREG-2192				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 070	Masonry walls: all	Cracking due to restraint shrinkage, creep, aggressive environment	AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Masonry Walls AMP will be used to manage cracking of masonry walls exposed to uncontrolled indoor air and outdoor air environments.
3.5-1, 071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S5, "Masonry Walls"	No	Not applicable. Structures at Turkey Point are not exposed to temperatures of 32ºF or less for sufficient durations that would cause freeze-thaw aging effects.
3.5-1, 072	Seals; gasket; moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage loss of sealing for seals and weatherproofing exposed to outdoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 073	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Not used. Loss of coating or lining integrity for Service Level I coatings is addressed under item number 3.5-1, 034.
3.5-1, 074	Sliding support bearings; sliding support surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, "Structures Monitoring"	No	Not applicable. There are no sliding support bearings or sliding support surfaces outside of containment in the Structures and Component Supports group. Applicable sliding components addressed under item 3.5-1, 075.
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, Section IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP will be used to manage sliding surfaces exposed to indoor air environment.
3.5-1, 076	This line item only applies to BWRs.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 077	Steel components: all structural steel	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage loss of material of structural steel components exposed to uncontrolled indoor air and outdoor air environments.
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. The Water Chemistry AMP, in conjunction with continued monitoring of spent fuel pool level and leak chase channel checks, will be used to manage cracking and loss of material of the stainless steel spent fuel pool liner exposed to treated borated water.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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	Not applicable. There are no steel piles in the Structures and Component Supports 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 with exception. The Structures Monitoring AMP will be used to manage loss of material for structural bolting exposed to uncontrolled indoor air and outdoor air environments. One NUREG-2191 line item is used for all supports associated with Section III, Component Supports for each structure since the component, material, environment, aging effect/mechanism, and AMP is consistent for each support type.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP will be used to manage loss of material for ASME Class 1, 2, and 3 component support bolting in uncontrolled indoor air environments. One NUREG-2191 line item is used for all supports associated with Section III, Component Supports for each structure since the component, material, environment, aging effect/mechanism, and AMP is consistent for each support type.
3.5-1, 082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Not used. Loss of material for structural bolting is addressed under item 3.5-1, 080.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 083	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be used to manage loss of material for structural bolting exposed to outdoor air and water – flowing or standing environments.
3.5-1, 084	There is no 3.5-1, 084 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, Section IWF"	No	Not applicable. There is no stainless steel structural bolting exposed to treated water environments in the Structures and Component Supports group.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWF"	No	There are no ASME class 1, 2, or 3 piping support structural bolting components exposed to outdoor air environments in the Structures and Component Supports group. Components are addressed under item 3.5-1, 088 for non-ASME structural bolting.
3.5-1, 087	Structural bolting	Loss of preload due to self-loosening	AMP XI.S3, "ASME Section XI, Section IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP will be used to manage loss of preload for structural bolting for ASME class 1, 2, and 3 piping supports exposed to uncontrolled indoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage loss of preload for structural bolting exposed to uncontrolled indoor air, controlled indoor air, and outdoor air environments.
3.5-1, 089	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion AMP will be used to manage loss of material for support members, welds, bolted connections, and support anchorage exposed to air with borated water leakage environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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, Section IWF"	No	Not applicable. There are no submerged structural components or structural components inside water storage tanks.
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, Section IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP will be used to manage loss of material for ASME Class 1, 2 and 3 support members, welds, bolted connections, and support anchorage exposed to uncontrolled indoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 092	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP will be used to manage loss of material for support members, welds, bolted connections, and support anchorage exposed to uncontrolled indoor air and outdoor air environments.
3.5-1, 093	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Not used. Loss of material for galvanized components is addressed under item 3.5-1, 092.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, "ASME Section XI, Section IWF," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP will be used to manage loss of material of vibration isolation elements exposed to uncontrolled indoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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. The Turkey Point AMR concluded that structural galvanized steel components exposed to indoor air environments have no applicable aging effects requiring management because there is no mechanism for constant wetting. For galvanized steel components exposed to air with borated water leakage environment, loss of material due to boric acid corrosion is addressed by 3.5-1, 089.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 096	Groups 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	No	Consistent with NUREG-2191. The Turkey Point Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be used to manage cracking for accessible concrete of Group 6 structures exposed to outdoor air, groundwater/soil, and water - flowing environments.
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 AMP	Yes (SRP-SLR Section 3.5.2.2.2.6)	A plant-specific AMP is not required for SLR. Further evaluation is documented in Section 3.5.2.2.2.6.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 098	Stainless steel, aluminum alloy support members; welds; bolted connections; support anchorage to building structure	None	None	No	Consistent with NUREG-2191. The Turkey Point AMR concluded that stainless steel components exposed to borated water leakage have no applicable aging effects requiring management.
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, Section IWF," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes (SRP-SLR Section 3.5.2.2.2.4)	The Turkey Point Structures Monitoring AMP will be used to manage loss of material for aluminum and stainless steel support members, welds, bolted connections, and support anchorage. This aging effect is addressed by 3.5-1, 100.

Table 3.5-1: Summary of Aging Management Evaluations for the Containment, 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 (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191. The Turkey Point Structures Monitoring AMP will be used to manage loss of material for aluminum and stainless steel support members, welds, bolted connections, and support anchorage exposed to uncontrolled indoor air, outdoor air, and water - flowing or standing environments.

Table 3.5.2-1
Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage components (post-tensioning system)	Structural support	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	ASME Section XI, Subsection IWL	II.A1.C-10	3.5-1, 032	A
Anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	A

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.TP-3	3.5-1, 089	A
Anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation	Structural support	Stainless steel	Air with borated water leakage	None	None	III.B3.TP-4	3.5-1, 098	A
ASME Class 1, 2 and 3 supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF	III.B1.1.T-24	3.5-1, 091	B
ASME Class 1, 2 and 3 supports	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B1.1.T-25	3.5-1, 089	A

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring	III.B3.TP-42	3.5-1, 055	B
Cable tray and conduits	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	C
Cable tray and conduits	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.TP-3	3.5-1, 089	C
Constant and variable load spring hangers, guides, stops	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF	III.B1.1.T-28	3.5-1, 057	B
Containment structure hatches and accessories	Pressure boundary Fire barrier	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of leak tightness	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A3.CP-39	3.5-1, 029	A
Containment structure hatches and accessories	Pressure boundary Fire barrier	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A3.C-16	3.5-1, 028	A

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Containment structure hatches and accessories	Pressure boundary Fire barrier	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B1.1.T-25	3.5-1, 089	C
Electrical instrument panels, enclosures and cabinets	Structural support Shelter, protection	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Electrical instrument panels, enclosures and cabinets	Structural support Shelter, protection	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	C
Electrical instrument panels, enclosures and cabinets	Structural support Shelter, protection	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	C
Electrical instrument panels, enclosures and cabinets	Structural support Shelter, protection	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.TP-3	3.5-1, 089	C

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Internal structural steel components	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A4.TP-302	3.5-1, 077	D
Internal structural steel components	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B1.1.T-25	3.5-1, 089	C
Liner plate	Pressure boundary Fire barrier	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Containment Liner Plate, Metal Containments, and Penetrations Fatigue	II.A3.C-13	3.5-1, 009	A
Liner plate moisture barrier (sealing compound)	Shelter, protection	Elastomer, rubber and other similar materials	Air – indoor uncontrolled	Loss of sealing	ASME Section XI, Subsection IWE	II.A3.CP-40	3.5-1, 026	A
Liner plate, anchors and attachments (accessible areas)	Pressure boundary Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A1.CP-35	3.5-1, 035	A
Liner plate, anchors and attachments (inaccessible areas)	Pressure boundary Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A1.CP-98	3.5-1, 005	A

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Liner plate, anchors and attachments	Pressure boundary Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B1.1.T-25	3.5-1, 089	C
NaTB sump fluid pH control basket	Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D
NaTB sump fluid pH control basket	Structural support	Stainless steel	Air with borated water leakage	None	None	III.B5.TP-4	3.5-1, 098	C
Penetration sleeves	Pressure boundary	Carbon steel	Air – indoor uncontrolled Air – outdoor	Cumulative fatigue damage	TLAA - Containment Liner Plate, Metal Containments, and Penetrations Fatigue	II.A3.C-13	3.5-1, 009	A
Penetration sleeves	Pressure boundary	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A3.CP-36	3.5-1, 035	A
Penetration sleeves	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B1.1.T-25	3.5-1, 089	C
Penetration sleeves	Pressure boundary	Dissimilar metal welds	Air – indoor uncontrolled Air – outdoor	Cracking	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A3.CP-38	3.5-1, 010	A

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pressure-retaining bolting	Pressure boundary Fire barrier	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	ASME Section XI, Subsection IWE	II.A3.CP-148	3.5-1, 031	A
Pressure-retaining bolting	Pressure boundary Fire barrier	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A3.CP-150	3.5-1, 030	A
Radiant energy shields	Fire barrier	Stainless steel	Air with borated water leakage	None	None	III.B5.TP-4	3.5-1, 098	C
Reinforced concrete containment structure (accessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL	II.A1.CP-68	3.5-1, 021	A
Reinforced concrete containment structure (accessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	ASME Section XI, Subsection IWL	II.A1.CP-87	3.5-1, 016	A

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete containment structure (accessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – outdoor Groundwater/ soil	Cracking	ASME Section XI, Subsection IWL	II.A1.CP-33	3.5-1, 019	A
Reinforced concrete containment structure (inaccessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – outdoor Groundwater/ soil	Cracking	Structures Monitoring	II.A1.CP-67	3.5-1, 012	B
Reinforced concrete containment structure (inaccessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – outdoor Groundwater/ soil	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL Structures Monitoring	II.A1.CP-97	3.5-1, 023	B, 1

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete containment structure (inaccessible)	Structural support Shelter, protection Fire barrier Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – outdoor Groundwater/ soil	Increase in porosity and permeability Cracking Loss of material	ASME Section XI, Subsection IWL Structures Monitoring	II.A1.CP-100	3.5-1, 024	B, 1
Reinforced concrete internal structural components (accessible)	Structural support Shelter, protection Missile barrier Shielding	Concrete	Air – indoor uncontrolled	Cracking	Structures Monitoring	III.A4.TP-25	3.5-1, 054	B
Reinforced concrete internal structural components (accessible)	Structural support Shelter, protection Missile barrier Shielding	Concrete	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	Structures Monitoring	III.A4.TP-26	3.5-1, 066	B

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete internal structural components (accessible)	Structural support Shelter, protection Missile barrier Shielding	Concrete	Air – indoor uncontrolled	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A4.TP-28	3.5-1, 067	B
Seals and gaskets	Pressure boundary	Elastomer, rubber and other similar materials	Air – indoor uncontrolled Air – outdoor	Loss of sealing	10 CFR Part 50, Appendix J	II.A3.CP-41	3.5-1, 033	A
Service Level I coatings	Shelter, protection	Coatings	Air – indoor uncontrolled	Loss of coating or lining integrity	Protective Coating Monitoring and Maintenance	II.A3.CP-152	3.5-1, 034	A
Sliding surfaces	Structural support	Lubrite®	Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF	III.B1.1.TP-45	3.5-1, 075	B
Structural bolting	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A4.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Carbon steel Galvanized steel Stainless steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring	III.A4.TP-261	3.5-1, 088	B

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Structural bolting: ASME Class 1, 2 and 3 supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF	III.B1.1.TP-226	3.5-1, 081	B
Structural bolting: ASME Class 1, 2 and 3 supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload	ASME Section XI, Subsection IWF	III.B1.1.TP-229	3.5-1, 087	B
Structural bolting: ASME Class 1 supports	Structural support	Carbon Steel (High Strength)	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWF	III.B1.1.TP-41	3.5-1, 068	B
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 1
Supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.T-25	3.5-1, 089	A
Supports for platforms, pipe whip restraints, and other miscellaneous structures	HELB shielding Pipe whip restraint Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Supports for platforms, pipe whip restraints, and other miscellaneous structures	HELB shielding Pipe whip restraint Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B5.T-25	3.5-1, 089	A
Supports for platforms, pipe whip restraints, and other miscellaneous structures	HELB shielding Pipe whip restraint Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	A

Table 3.5.2-1: Containment Structure and Internal Structural Components — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Supports for platforms, pipe whip restraints, and other miscellaneous structures	HELB shielding Pipe whip restraint Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B5.TP-3	3.5-1, 089	A
Supports for platforms, pipe whip restraints, and other miscellaneous structures	HELB shielding Pipe whip restraint Structural support	Stainless steel	Air with borated water leakage	None	None	III.B5.TP-4	3.5-1, 098	A
Tendons (post-tensioning system)	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWL	II.A1.C-10	3.5-1, 032	A
Tendons (post-tensioning system)	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of prestress	TLAA - Section 4.5, Concrete Containment Tendon Prestress	II.A1.C-11	3.5-1, 008	A
Vibration isolation elements	Structural support	Elastomer, rubber and other similar materials	Air – indoor uncontrolled	Reduction or loss of isolation function	ASME Section XI, Subsection IWF	III.B1.1.T-33	3.5-1, 094	B

Notes for Table 3.5.2-1

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes for Table 3.5.2-1

1. Note B applies to the Structures Monitoring AMP only.

Table 3.5.2-2
Auxiliary Building — Summary of Aging Management Evaluation

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Anchorage/ embedment	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (above and below groundwater elevation)	Structural support	Concrete Grout	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B3.TP-42	3.5-1, 055	B
Charging pump monorails	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Charging pump monorails	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Charging pump monorails bolting	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
Drains and drain plugs (stored)	Flood barrier	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D
Drain plugs (stored)	Flood barrier	Elastomer, rubber and other similar materials	Air – indoor uncontrolled Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	C

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	C
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.TP-3	3.5-1, 089	C
Electrical component supports	Structural support	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Electrical component supports	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	A

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Electrical component supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Electrical component supports	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Electrical component supports	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.TP-3	3.5-1, 089	A
Fan/filter intake hood	Shelter, protection	Stainless steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.T-37b	3.5-1, 100	D
HVAC and pipe supports	Structural support	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
HVAC and pipe supports	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.T-25	3.5-1, 089	A
HVAC and pipe supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
HVAC and pipe supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
HVAC and pipe supports	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
HVAC and pipe supports	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.TP-3	3.5-1, 089	A
Instrument racks and frames	Structural support	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Instrument racks and frames	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	C
Instrument racks and frames	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Instrument racks and frames	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	C
Instrument racks and frames	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Instrument racks and frames	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.TP-3	3.5-1, 089	C
Miscellaneous steel	HELB shielding	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Miscellaneous steel	HELB shielding	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B5.T-25	3.5-1, 089	A

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Masonry block walls (reinforced)	Structural support Shelter, protection	Concrete block	Air – indoor uncontrolled	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A
Masonry block walls (unreinforced)	Flood barrier Structural support Shelter, protection	Concrete block	Air – indoor uncontrolled Air-outdoor	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A
Pipe trench penetration seals	Flood barrier	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B
Pipe whip restraints	Pipe whip restraint	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Pipe whip restraints	Pipe whip restraint	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B5.T-25	3.5-1, 089	A
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Groundwater/soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Groundwater/ soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Groundwater/ soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 3
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Groundwater/ soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Groundwater/soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B, 2

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B, 2
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 3
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	D, 2
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B, 2

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Safety injection pump monorails	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Safety injection pump monorails	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Safety injection pump monorails bolting	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
Stairs, platforms, grating and supports	Structural support Missile barrier	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	D, 1
Stairs, platforms, grating and supports	Structural support Missile barrier	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B5.T-25	3.5-1, 089	C, 1
Stairs, platforms, grating and supports	Structural Support Missile barrier	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C, 1
Stairs, platforms, grating and supports	Structural support Missile barrier	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	C, 1

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Stairs, platforms, grating and supports	Structural support Missile barrier	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	D, 1
Stairs, platforms, grating and supports	Structural support Missile barrier	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B5.TP-3	3.5-1, 089	C, 1
Steel cable tray and conduits supports	Structural support	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
Steel cable tray and conduits supports	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.T-25	3.5-1, 089	A
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Steel cable tray and conduits supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Steel cable tray and conduits supports	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
Steel cable tray and conduits supports	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.TP-3	3.5-1, 089	A

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	C
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.TP-3	3.5-1, 089	C
Stop logs	Flood barrier	Aluminum	Air – outdoor	Loss of material	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 4

Table 3.5.2-2: Auxiliary Building — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete block	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 4
Structural steel: beams, columns, and connections	Structural support	Carbon steel	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B, 2
Structural steel: beams, columns, and connections	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	A
Weatherproofing	Shelter, protection	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	D

Notes for Table 3.5.2-2

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.5.2-2

1. Some grating performs missile barrier function.
2. The components that are exposed to indoor controlled air are assumed to experience the same aging effects as if the components were exposed to indoor uncontrolled air.
3. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.
4. Note B applies to the Structures Monitoring AMP only.

Table 3.5.2-3
Cold Chemistry Lab — Summary of Aging Management Evaluation

Table 3.5.2-3: Cold Chemistry Lab — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B

Table 3.5.2-3: Cold Chemistry Lab — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete: interior and above grade exterior (accessible)	Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1

Table 3.5.2-3: Cold Chemistry Lab — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	D
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B

Notes for Table 3.5.2-3

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.5.2-3

1. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.

Table 3.5.2-4
Control Building — Summary of Aging Management Evaluation

Table 3.5.2-4: Control Building — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor controlled	Loss of preload	Structures Monitoring	III.A1.TP-261	3.5-1, 088	B
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – indoor controlled	Reduction in concrete anchor capacity	Structures Monitoring	III.B3.TP-42	3.5-1, 055	B
Control Room ceiling	Structural support	Gypsum board Acoustical panels	Air – indoor controlled	None	None	–	–	J, 3
Control Room raised floor	Structural support	Tee Cor panel Micarta Cove base Steel supports	Air – indoor controlled	None	None	–	–	J, 3

Table 3.5.2-4: Control Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Stainless steel	Air – indoor controlled	None	None	–	–	J, 3
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
HVAC and pipe supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Instrument racks and frames	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C

Table 3.5.2-4: Control Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Masonry block walls (reinforced)	Structural support Shelter, protection Missile barrier	Concrete block	Air – indoor controlled	Cracking	Masonry Walls	III.A1.T-12	3.5-1, 070	A
Masonry block walls (unreinforced)	Structural support Shelter, protection Missile barrier	Concrete block	Air – indoor controlled	Cracking	Masonry Walls	III.A1.T-12	3.5-1, 070	A
Miscellaneous steel	Structural support Shelter, protection Missile barrier	Carbon steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Miscellaneous steel	Structural support Shelter, protection Missile barrier	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.A1.TP-302	3.5-1, 077	B
Penetration seals	Pressure boundary	Elastomer, rubber and other similar materials	Air – indoor controlled Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B

Table 3.5.2-4: Control Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A1.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A1.TP-27	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A1.TP-204	3.5-1, 043	E, 2
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A1.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A1.TP-29	3.5-1, 067	B

Table 3.5.2-4: Control Building — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete: interior and above grade exterior (accessible)	Pressure boundary Structural support Shelter, protection Missile barrier	Concrete	Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A1.TP-25	3.5-1, 054	B
Reinforced concrete: interior and above grade exterior (accessible)	Pressure boundary Structural support Shelter, protection Missile barrier	Concrete	Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A1.TP-26	3.5-1, 066	B, 1
Reinforced concrete: interior and above grade exterior (accessible)	Pressure boundary Structural support Shelter, protection Missile barrier	Concrete	Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A1.TP-28	3.5-1, 067	B, 1

Table 3.5.2-4: Control Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: interior and above grade exterior (inaccessible)	Pressure boundary Structural support Shelter, protection Missile barrier	Concrete	Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A1.TP-204	3.5-1, 043	E, 2
Reinforced concrete: interior and above grade exterior (inaccessible)	Pressure boundary Structural support Shelter, protection Missile barrier	Concrete	Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A1.TP-26	3.5-1, 066	D, 1
Reinforced concrete: interior and above grade exterior (inaccessible)	Pressure boundary Structural support Shelter, protection Missile barrier	Concrete	Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A1.TP-28	3.5-1, 067	B, 1
Stairs, platforms, grating and supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C

Table 3.5.2-4: Control Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete	Air – indoor controlled Air – outdoor	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 4
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete block	Air – indoor controlled	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 4
Structural steel: beams, columns, and connections	Structural support	Carbon steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Weatherproofing	Shelter, protection	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B

Notes for Table 3.5.2-4

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant-Specific Notes for Table 3.5.2-4

1. The components that are exposed to indoor controlled air are assumed to experience the same aging effects as if the components were exposed to indoor uncontrolled air.
2. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.
3. These components do not have aging effects in controlled air.
4. Note B Applies to the Structures Monitoring AMP only.

Table 3.5.2-5
Cooling Water Canals —
Summary of Aging Management Evaluation

Table 3.5.2-5: Cooling Water Canals — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Earthen canal	Heat sink	Various	Air – outdoor Water - flowing or standing	Loss of material Loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-22	3.5-1, 058	A

Notes for Table 3.5.2-5

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.5.2-6
Diesel Driven Fire Pump Enclosure — Summary of Aging Management Evaluation

Table 3.5.2-6: Diesel Driven Fire Pump Enclosure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Anchorage/ embedment	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B3.TP-42	3.5-1, 055	B
Doors	Shelter, protection	Aluminum	Air – outdoor	Loss of material	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D
Louvers	Shelter, protection	Aluminum	Air – outdoor	Loss of material	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D
Manufactured structure	Shelter, protection	Aluminum	Air – outdoor	Loss of material	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D

Table 3.5.2-6: Diesel Driven Fire Pump Enclosure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Manufactured structure	Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B
Pipe supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1

Table 3.5.2-6: Diesel Driven Fire Pump Enclosure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B

Notes for Table 3.5.2-6

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.5.2-6

1. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.

Table 3.5.2-7
Discharge Structure — Summary of Aging Management Evaluation

Table 3.5.2-7: Discharge Structure — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B5.TP-42	3.5-1, 055	B
Reinforced concrete North and South headwall (accessible)	Structural support	Concrete	Air – outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-34	3.5-1, 096	A
Reinforced concrete North and South headwall (accessible)	Structural support	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-38	3.5-1, 059	A
Reinforced concrete North and South headwall (accessible)	Structural support	Concrete	Air – outdoor	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-37	3.5-1, 061	A

Table 3.5.2-7: Discharge Structure — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete North and South headwall (accessible)	Structural support	Concrete	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-20	3.5-1, 056	A
Reinforced concrete North and South headwall (inaccessible)	Structural support	Concrete	Air –outdoor Groundwater/ soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A6.TP-104	3.5-1, 065	B
Reinforced concrete North and South headwall (inaccessible)	Structural support	Concrete	Air – outdoor Groundwater/ soil Water-flowing	Cracking	Structures Monitoring	III.A6.TP-220	3.5-1, 050	E, 1
Reinforced concrete North and South headwall (inaccessible)	Structural support	Concrete	Groundwater/ soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A6.TP-107	3.5-1, 067	B
Reinforced concrete North and South headwall (inaccessible)	Structural support	Concrete	Water - flowing	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A6.TP-109	3.5-1, 051	E, 2

Table 3.5.2-7: Discharge Structure — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete North and South headwall (inaccessible)	Structural support	Concrete	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-20	3.5-1, 056	A
Reinforced concrete seal wall (accessible)	Structural support	Concrete	Air – outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-34	3.5-1, 096	B
Reinforced concrete seal wall (accessible)	Structural support	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-38	3.5-1, 059	B
Reinforced concrete seal wall (accessible)	Structural support	Concrete	Air – outdoor	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-37	3.5-1, 061	B

Table 3.5.2-7: Discharge Structure — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete seal wall (accessible)	Structural support	Concrete	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-20	3.5-1, 056	A
Reinforced concrete seal wall (inaccessible)	Structural support	Concrete	Air –outdoor Groundwater/ soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A6.TP-104	3.5-1, 065	B
Reinforced concrete seal wall (inaccessible)	Structural support	Concrete	Air – outdoor Groundwater/ soil Water-flowing	Cracking	Structures Monitoring	III.A6.TP-220	3.5-1, 050	E, 1
Reinforced concrete seal wall (inaccessible)	Structural support	Concrete	Groundwater/ soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A6.TP-107	3.5-1, 067	B

Table 3.5.2-7: Discharge Structure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete seal wall (inaccessible)	Structural support	Concrete	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring	III.A6.TP-109	3.5-1, 051	E, 2
Reinforced concrete seal wall (inaccessible)	Structural support	Concrete	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-20	3.5-1, 056	C

Notes for Table 3.5.2-7

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.5.2-7

1. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.
2. The Structures Monitoring AMP will be used to manage increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation.

Table 3.5.2-8
Electrical Penetration Rooms — Summary of Aging Management Evaluation

Table 3.5.2-8: Electrical Penetration Rooms — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Anchorage/ embedment	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring	III.B3.TP-42	3.5-1, 055	B
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D

Table 3.5.2-8: Electrical Penetration Rooms — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	C
Electrical component supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Electrical component supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Instrument racks and frames	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Ladders and platforms	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	D
Ladders and platforms	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	C
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B

Table 3.5.2-8: Electrical Penetration Rooms — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Reinforced concrete: interior and above grade exterior (accessible)	Missile barrier Shelter, protection Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: interior and above grade exterior (accessible)	Missile barrier Shelter, protection Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B

Table 3.5.2-8: Electrical Penetration Rooms — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: interior and above grade exterior (accessible)	Missile barrier Shelter, protection Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B
Reinforced concrete: interior and above grade exterior (inaccessible)	Missile barrier Shelter, protection Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	D
Reinforced concrete: interior and above grade exterior (inaccessible)	Missile barrier Shelter, protection Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Reinforced concrete: interior and above grade exterior (inaccessible)	Missile barrier Shelter, protection Structural support	Concrete	Air – indoor uncontrolled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B
Steel cable tray and conduits supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B

Table 3.5.2-8: Electrical Penetration Rooms — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel cable tray and conduits supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Steel cable trays and conduits	Structural support Shelter, protection	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	C
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 2
Structural steel	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B
Weatherproofing	Shelter, protection	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B

Notes for Table 3.5.2-8

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.5.2-8

1. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.
2. Note B Applies to the Structures Monitoring AMP only.

Table 3.5.2-9
Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – indoor uncontrolled Air – indoor controlled	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Anchorage/ embedment	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – indoor uncontrolled Air – indoor controlled	Reduction in concrete anchor capacity	Structures Monitoring	III.B2.TP-42	3.5-1, 055	B
Drains and drain plugs (stored)	Flood barrier	Carbon steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Drain plugs (stored)	Flood barrier	Elastomer, rubber and other similar materials	Air – indoor uncontrolled Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	D
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	C
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Stainless steel	Air – indoor controlled	None	None	–	–	J, 5
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Stainless steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical component supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Electrical component supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
HVAC and pipe supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
HVAC and pipe supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
HVAC and pipe supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
HVAC and pipe supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
HVAC roof hoods	Structural support	Stainless steel	Air – outdoor	Loss of material	Structures Monitoring	III.B4.T-37b	3.5-1, 100	D
Instrument racks and frames	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument racks and frames	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	C
Instrument racks and frames	Structural support	Stainless steel	Air – indoor controlled	None	None	–	–	J, 5
Instrument racks and frames	Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material Cracking	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Instrument racks and frames	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Louvers	Shelter, protection	Aluminum	Air – outdoor	Loss of material Cracking	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Masonry block walls (reinforced)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete block	Air – indoor uncontrolled Air – outdoor	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A
Masonry block walls (unreinforced)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete block	Air – indoor uncontrolled	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Miscellaneous steel	Structural support Shelter, protection Missile barrier	Carbon steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Miscellaneous steel	Structural support Shelter, protection Missile barrier	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 2

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B, 1

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B, 1
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	D, 1
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 2
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B, 1

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Stairs, platforms, grating and supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	D
Stairs, platforms, grating and supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	C
Stairs, platforms, grating and supports	Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material Cracking	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D
Stairs, platforms, grating and supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Steel cable tray and conduits supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
Steel cable tray and conduits supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	C
Steel supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B4.TP-43	3.5-1, 092	B
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 3
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete block	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 3
Structural steel: beams, columns, and connections	Structural support	Carbon steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Structural steel: beams, columns, and connections	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B

Table 3.5.2-9: Emergency Diesel Generator Buildings — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
U4 DOST liner	Pressure boundary	Carbon steel	Concrete	None	None	--	--	J, 4
U4 DOST liner	Pressure boundary	Carbon steel	Fuel oil	Loss of material	Fuel Oil Chemistry	VII.H1.AP-105a	3.3-1, 070	B
Weatherproofing	Shelter, protection	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B

Notes for Table 3.5.2-9

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

<u>Plant-Specific Notes for Table 3.5.2-9</u>

1. The components that are exposed to indoor controlled air are assumed to experience the same aging effects as if the components were exposed to indoor uncontrolled air.
2. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.
3. Note B Applies to the Structures Monitoring AMP only.
4. External surface of the liner is embedded in concrete and not subject to age-related degradation.
5. Stainless steel component types are exposed to air-indoor controlled environment do not have any aging effects that require aging management.

Table 3.5.2-10
Fire Rated Assemblies — Summary of Aging Management Evaluation

Table 3.5.2-10: Fire Rated Assemblies — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Drip shields over Thermo-lag	Fire barrier	Stainless steel	Air – outdoor	Loss of material Cracking	Fire Protection	III.B2.T-37b	3.5-1, 100	E
Electrical fireproofing protection	Fire barrier	Thermo-lag	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Hardening Loss of strength Shrinkage	Fire Protection	VII.G.A-19	3.3-1, 057	C
Fire doors	Fire barrier	Carbon steel	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Loss of material	Fire Protection	VII.G.A-21	3.3-1, 059	A
Fire doors between Cable Spreading Room and AC Fan Room	Shelter, protection Fire barrier	Carbon steel	Air – indoor uncontrolled Air – indoor controlled	Loss of material	Fire Protection	VII.G.A-21	3.3-1, 059	A
Fire doors, Control Room	Pressure boundary Shelter, protection Fire barrier	Carbon steel	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Loss of material	Fire Protection	VII.G.A-21	3.3-1, 059	A

Table 3.5.2-10: Fire Rated Assemblies — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Fire retardant coating	Fire barrier	Flamemastic	Air – indoor uncontrolled Air – indoor controlled	Hardening Loss of strength Shrinkage	Fire Protection	VII.G.A-19	3.3-1, 057	A
Fire sealed isolation joint	Fire barrier	Cerafiber	Air – outdoor	Hardening Loss of strength Shrinkage	Fire Protection	VII.G.A-19	3.3-1, 057	A
Fire sealed isolation joint	Flood barrier	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B
Penetration seals	Fire barrier	Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Penetration seals	Fire barrier	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	C
Penetration seals	Fire barrier	Elastomer, rubber, and other similar materials	Air – indoor uncontrolled Air – indoor controlled	Hardening Loss of strength Shrinkage	Fire Protection	VII.G.A-19	3.3-1, 057	A
Penetration seals (pipe trench)	Flood barrier	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B

Table 3.5.2-10: Fire Rated Assemblies — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Seals and gaskets (doors, manways, and hatches)	Fire barrier	Elastomer, rubber, and other similar materials	Air – outdoor	Hardening Loss of strength Shrinkage	Fire Protection	VII.G.A-19	3.3-1, 057	A
Seals and gaskets (doors, manways, and hatches	Flood barrier	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B
Structural steel fireproofing	Fire barrier	Cementitious fireproofing	Air – indoor uncontrolled Air – indoor controlled	Hardening Loss of strength Shrinkage	Fire Protection	VII.G.A-19	3.3-1, 057	J, 2

Notes for Table 3.5.2-10

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant-Specific Notes for Table 3.5.2-10

1. The components that are exposed to indoor controlled air are assumed to experience the same aging effects as if the components were exposed to indoor uncontrolled air.
2. Component and material are different, but consistent with environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Table 3.5.2-11
Intake Structure — Summary of Aging Management Evaluation

Table 3.5.2-11: Intake Structure — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment (above Intake canal level)	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-221	3.5-1, 083	A
Anchorage/ embedment (above Intake canal level)	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of preload	Structures Monitoring	III.A6.TP-261	3.5-1, 088	A
Anchorage/ embedment (below Intake canal level)	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of preload	Structures Monitoring	III.A6.TP-261	3.5-1, 088	A
Anchorage/ embedment (below Intake canal level)	Structural support	Carbon steel Galvanized steel	Air – outdoor Water - flowing or standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-221	3.5-1, 083	A

Table 3.5.2-11: Intake Structure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B5.TP-42	3.5-1, 055	B
Electrical component supports	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Electrical enclosures	Structural support Shelter, protection	Stainless steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Electrical enclosures	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Electrical instrument racks and frames	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D

Table 3.5.2-11: Intake Structure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
ICW Valve Pit rigging beam	Structural support	Carbon steel Galvanized steel	Air – outdoor	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
ICW Valve Pit rigging beam	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Intake Structure Cranes	Structural support	Carbon steel	Air – outdoor	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Intake Structure Cranes	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Intake Structure Traveling Screen cloth	Filter	Stainless steel	Air – outdoor Water - flowing or standing	Loss of material Cracking	Structures Monitoring	–	–	J
Intake Structure Traveling Screen frames	Structural support	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	D

Table 3.5.2-11: Intake Structure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Masonry block walls	Flood barrier	Concrete block	Air – outdoor	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A
Reinforced concrete foundation, beams, columns, walls and floors/ slabs (above Intake Canal level)	Structural support	Concrete	Air – outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-34	3.5-1, 096	B
Reinforced concrete foundation, beams, columns, walls and floors/ slabs (above Intake Canal level)	Structural support	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-38	3.5-1, 059	B
Reinforced concrete foundation, beams, columns, walls and floors/ slabs (above Intake Canal level)	Structural support	Concrete	Air – outdoor	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-37	3.5-1, 061	B

Table 3.5.2-11: Intake Structure — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reinforced concrete foundation, beams, columns, walls and floors/ slabs (above Intake Canal level)	Structural support	Concrete	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-20	3.5-1, 056	A
Reinforced concrete foundations, beams, columns, walls, floors/slabs (below Intake Canal level)	Structural support	Concrete	Air –outdoor Groundwater/ soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A6.TP-104	3.5-1, 065	B
Reinforced concrete foundations, beams, columns, walls, floors/slabs (below Intake Canal level)	Structural support	Concrete	Air – outdoor Groundwater/ soil Water-flowing	Cracking	Structures Monitoring	III.A6.TP-220	3.5-1, 050	E, 1

Table 3.5.2-11: Intake Structure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete foundations, beams, columns, walls, floors/slabs (below Intake Canal level)	Structural support	Concrete	Groundwater/ soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A6.TP-107	3.5-1, 067	B
Reinforced concrete foundations, beams, columns, walls, floors/slabs (below Intake Canal level)	Structural support	Concrete	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring	III.A6.TP-109	3.5-1, 051	E, 2
Reinforced concrete foundations, beams, columns, walls, floors/slabs (below Intake Canal level)	Structural support	Concrete	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.T-20	3.5-1, 056	A
Stairs, platforms, grating and supports	Structural support	Stainless steel	Air – outdoor	Loss of material Cracking	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D

Table 3.5.2-11: Intake Structure — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Stairs, platforms, grating and supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-221	3.5-1, 083	C
Steel cable tray and conduits supports	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
Steel cable trays and conduits	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D
Steel supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Structural steel: beams, columns, and connections	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants	III.A6.TP-221	3.5-1, 083	C
Structural truck bridge	Structural support	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	D
Trolley frame	Structural support	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D

Notes for Table 3.5.2-11

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant-Specific Notes for Table 3.5.2-11

1. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.
2. The Structures Monitoring AMP will be used to manage increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation.

Table 3.5.2-12
Main Steam and Feedwater Platforms — Summary of Aging Management Evaluation

Table 3.5.2-12: Main Steam and Feedwater Platforms — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B2.TP-42	3.5-1, 055	B
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B

Table 3.5.2-12: Main Steam and Feedwater Platforms — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
HVAC and pipe supports	Structural support	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
Instrument racks and frames	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Main Steam platform monorails	Structural support	Carbon steel	Air – outdoor	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Main Steam platform monorails	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Miscellaneous steel	HELB shielding	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B
Pipe whip restraints	Pipe whip restraint	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Reinforced concrete: above grade exterior (accessible)	Structural support Shelter, protection Missile barrier	Concrete	Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B

Table 3.5.2-12: Main Steam and Feedwater Platforms — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: above grade exterior (accessible)	Structural support Shelter, protection Missile barrier	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Reinforced concrete: above grade exterior (accessible)	Structural support Shelter, protection Missile barrier	Concrete	Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B
Reinforced concrete: above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	D
Reinforced concrete: above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier	Concrete	Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Reinforced concrete: above grade exterior (inaccessible)	Structural support Shelter, protection Missile barrier	Concrete	Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B

Table 3.5.2-12: Main Steam and Feedwater Platforms — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Stairs, platforms, grating and supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	D

Table 3.5.2-12: Main Steam and Feedwater Platforms — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D
Structural steel: beams, columns, and connections	Structural support	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B

Notes for Table 3.5.2-12

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.5.2-12

1. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.

Table 3.5.2-13
Plant Vent Stack — Summary
of Aging Management Evaluation

Table 3.5.2-13: Plant Vent Stack — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B2.TP-42	3.5-1, 055	B
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Steel conduits and conduits supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B

Table 3.5.2-13: Plant Vent Stack — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural steel supports/ restraints	Structural support	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B
Vent stack	Structural support Gaseous release path	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	D

Notes for Table 3.5.2-13

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.5.2-14
Polar Cranes — Summary
of Aging Management Evaluation

Table 3.5.2-14: Polar Cranes— Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Cab	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Control conductor supports	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Electrical enclosures	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Electrical enclosures	Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material Cracking	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
End connectors (fasteners)	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A

Table 3.5.2-14: Polar Cranes— Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Footwalks and railings	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Main girders	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Runway rail brackets	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Runway rail brackets	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Runway rails	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Runway rails	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A

Table 3.5.2-14: Polar Cranes— Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Trolley rails	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Trolley rails	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Trolley structure	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Trolley structure	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A

Notes for Table 3.5.2-14

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.5.2-15
Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring	III.B2.TP-42	3.5-1, 055	B
Fuel assembly transfer system reactor side kick spring assembly	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Fuel assembly transfer system reactor side lifting frame assembly	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Fuel assembly transfer system reactor side lifting frame assembly	Structural support	Stainless steel	Treated borated water >60°C (>140°F)	Cracking	Water Chemistry One Time Inspection	VII.A2.A-97	3.3-1, 124	C
Fuel assembly transfer system reactor side sheave frame	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Fuel assembly transfer system reactor side sheave frame	Structural support	Stainless steel	Treated borated water >60°C (>140°F)	Cracking	Water Chemistry One Time Inspection	VII.A2.A-97	3.3-1, 124	C
Fuel assembly transfer system Spent Fuel Pit side kick spring	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Fuel assembly transfer system Spent Fuel Pit side sheave frame	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Fuel assembly transfer system Spent Fuel Pit side sheave frame	Structural support	Stainless steel	Treated borated water >60°C (>140°F)	Cracking	Water Chemistry One Time Inspection	VII.A2.A-97	3.3-1, 124	C
Fuel transfer machine	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Fuel transfer machine	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Fuel transfer machine bolting	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
Fuel transfer tube (including penetration sleeves and expansion joints)	Pressure boundary	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Fuel transfer tube (including penetration sleeves and expansion joints)	Pressure boundary	Stainless steel	Air – indoor uncontrolled Air – outdoor	Cracking	ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	II.A3.CP-38	3.5-1, 010	A
Fuel transfer tube blind flange	Pressure boundary	Carbon steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Fuel transfer tube blind flange devit	Structural support	Carbon steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fuel pool bulkhead monorail	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Fuel pool bulkhead monorail	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Fuel pool bulkhead monorail bolting	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
New fuel storage components	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material	Structures monitoring	VII.A1.A-94	3.3-1, 111	B
Overhead door	Shelter, protection Fire barrier Missile barrier	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Overhead door	Shelter, protection Fire barrier Missile barrier	Concrete	Air – indoor uncontrolled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor Cavity Manipulator Crane	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Reactor Cavity Manipulator Crane	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Reactor Cavity Manipulator Crane	Structural support	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.T-25	3.5-1, 089	A
Reactor Cavity Manipulator Crane bolting	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
Reactor cavity seal ring segmented cavity seals (alternate)	Pressure boundary	Stainless steel	Air – indoor uncontrolled Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Refueling Pool liner	Pressure boundary	Stainless steel	Treated borated water >60°C (>140°F)	Cracking Loss of material	Water Chemistry and monitoring of the spent fuel pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	A, 1
Spent Fuel assembly handling tool	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Spent Fuel Bridge Crane	Structural support	Carbon steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Spent Fuel Bridge Crane	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Spent Fuel Cask Crane	Structural support	Carbon steel	Air – outdoor	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Spent Fuel Cask Crane	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Spent Fuel Bridge, Cask Crane bolting	Structural support	Carbon steel	Air – indoor uncontrolled	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
Spent Fuel Pool keyway gate	Pressure boundary	Stainless steel	Air – indoor uncontrolled Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Spent Fuel Pool keyway gate	Pressure boundary	Stainless steel	Air – indoor uncontrolled Treated borated water >60°C (>140°F)	Cracking	Water Chemistry One Time Inspection	VII.A2.A-97	3.3-1, 124	C

Table 3.5.2-15:Spent Fuel Storage and Handling — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Spent Fuel Pool and Transfer Canal liner	Pressure boundary	Stainless steel	Treated borated water >60°C (>140°F)	Cracking Loss of material	Water Chemistry and monitoring of the spent fuel pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	A, 1
Spent Fuel storage racks	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry One Time Inspection	VII.A2.A-99	3.3-1, 125	C
Spent fuel storage rack inserts	Absorbs neutrons	Boral	Treated borated water	Reduction of neutron-absorbing capacity Change in dimensions Loss of material	Monitoring of Neutron-Absorbing Materials other than Boraflex	VII.A2.AP-235	3.3-1, 102	A
Spent fuel storage rack inserts	Absorbs neutrons	Metamic®	Treated borated water	Reduction of neutron-absorbing capacity Change in dimensions Loss of material	Monitoring of Neutron-Absorbing Materials other than Boraflex	VII.A2.AP-235	3.3-1, 102	A

Notes for Table 3.5.2-15

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes for Table 3.5.2-15

1. Monitoring of the spent fuel pool water level and leakage from the leak chase channels at Turkey Point is and will continue to be performed. See Appendix A.

Table 3.5.2-16
Turbine Building — Summary of Aging Management Evaluation

Table 3.5.2-16: Turbine Building — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – indoor controlled Air – outdoor	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – indoor controlled Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – indoor controlled Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B2.TP-42	3.5-1, 055	B
Drains and drain plugs (stored)	Flood barrier	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Drain plugs (stored)	Flood barrier	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B
Electrical and instrument panels and enclosures	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C

Table 3.5.2-16: Turbine Building — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Electrical and instrument panels and enclosures	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Flood seals for pipe trench (Promatec flexible pressure seals)	Flood barrier	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	D
Instrument racks and frames	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Masonry block walls (reinforced)	Structural support Shelter, protection	Concrete block	Air – indoor controlled	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A

Table 3.5.2-16: Turbine Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Masonry block walls (unreinforced)	Structural support Shelter, protection Flood barrier	Concrete block	Air – outdoor	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A
Miscellaneous steel	HELB shielding	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Perimeter stop logs	Flood barrier	Aluminum	Air – outdoor	Loss of material	Structures Monitoring	III.B5.T-37b	3.5-1, 100	B
Pipe whip restraints	Pipe whip restraint	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: foundation (accessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 2

Table 3.5.2-16: Turbine Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete: foundation (inaccessible)	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection	Concrete	Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection	Concrete	Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B, 1
Reinforced concrete: interior and above grade exterior (accessible)	Structural support Shelter, protection	Concrete	Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B, 1

Table 3.5.2-16: Turbine Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection	Concrete	Air – indoor controlled Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 2
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection	Concrete	Air – indoor controlled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	D, 1
Reinforced concrete: interior and above grade exterior (inaccessible)	Structural support Shelter, protection	Concrete	Air – indoor controlled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-28	3.5-1, 067	B, 1
Stairs, platforms, grating and supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B

Table 3.5.2-16: Turbine Building — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	C
Steel cable trays and conduits	Structural support Shelter, protection	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete	Air – indoor controlled Air – outdoor	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 3
Structural fire barriers: walls, ceilings and floors	Fire barrier	Concrete block	Air – indoor controlled Air – outdoor	Cracking Loss of material	Fire Protection Structures Monitoring	VII.G.A-90	3.3-1, 060	B, 3
Structural steel	Structural support	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B
Weatherproofing	Shelter, protection	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B

Notes for Table 3.5.2-16

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes for Table 3.5.2-16

1. The components that are exposed to indoor controlled air are assumed to experience the same aging effects as if the components were exposed to indoor uncontrolled air.
2. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.
3. Note B Applies to the Structures Monitoring AMP only.

Table 3.5.2-17
Turbine Gantry Cranes — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Cab	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Electrical and instrument panels and enclosures	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D
Ladder and stairways	Structural support	Aluminum	Air – outdoor	Loss of material Cracking	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Leg end frames	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Leg truck beams	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A

Table 3.5.2-17: Turbine Gantry Cranes — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Main girders	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Platforms	Structural support	Carbon steel	Air – outdoor	Loss of material Cracking	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Rail anchorage/ embedment	Structural support	Carbon steel	Air – outdoor	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
Railings	Structural support	Carbon steel	Air – outdoor	Loss of material Cracking	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Runway rails	Structural support	Carbon steel	Air – outdoor	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
Runway rails	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Trolley rails	Structural support	Carbon steel	Air – outdoor	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A

Table 3.5.2-17: Turbine Gantry Cranes — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Trolley rails	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A
Trolley structure	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A

Notes for Table 3.5.2-17

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Table 3.5.2-18
Yard Structures — Summary of Aging Management Evaluation

Table 3.5.2-18:Yard Structures — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-248	3.5-1, 080	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of preload	Structures Monitoring	III.A3.TP-261	3.5-1, 088	B
Anchorage/ embedment	Structural support	Carbon steel Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	A
Berm	Flood barrier	Earth	Air – outdoor	Loss of material Loss of form	Structures Monitoring	--	--	J
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete Grout	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring	III.B2.TP-42	3.5-1, 055	B
Drains and drain plugs (stored)	Flood barrier	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D

Table 3.5.2-18: Yard Structures — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Drain plugs (stored)	Flood barrier	Elastomer, rubber and other similar materials	Air – outdoor	Loss of sealing	Structures Monitoring	III.A6.TP-7	3.5-1, 072	B
Duct banks	Structural support Shelter, protection	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Duct banks	Structural support Shelter, protection	Concrete	Air –outdoor Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Duct banks	Structural support Shelter, protection	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Duct banks	Structural support Shelter, protection	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	D

Table 3.5.2-18: Yard Structures — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical and instrument panels and enclosures	Structural support Shelter, protection	Stainless steel	Air – outdoor	Loss of material, cracking	Structures Monitoring	III.B3.T-37b	3.5-1, 100	D
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Electrical component supports	Structural support	Carbon steel Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	A
Electrical manholes	Structural support Shelter, protection	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Electrical manholes	Structural support Shelter, protection	Concrete	Air –outdoor Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Electrical manholes	Structural support Shelter, protection	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B

Table 3.5.2-18: Yard Structures — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical manholes	Structural support Shelter, protection	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Equipment foundations	Structural support	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Equipment foundations	Structural support	Concrete	Air –outdoor Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Equipment foundations	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Equipment foundations	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Gravel pits and curbs	Structural support	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Gravel pits and curbs	Structural support	Concrete	Air –outdoor Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5-1, 054	B

Table 3.5.2-18: Yard Structures — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Gravel pits and curbs	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Gravel pits and curbs	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Instrument racks and frames	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Masonry block walls	Flood barrier	Concrete block	Air – outdoor	Cracking	Masonry Walls	III.A3.T-12	3.5-1, 070	A
Miscellaneous raceway and pipe supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B3.TP-43	3.5-1, 092	B
Miscellaneous raceway and pipe supports	Structural support	Carbon steel Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B3.T-25	3.5-1, 089	A
Miscellaneous steel structures	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B

Table 3.5.2-18: Yard Structures — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Miscellaneous steel structures	Structural support	Carbon steel Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B5.T-25	3.5-1, 089	A
Pipe trenches	Structural support	Concrete	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-26	3.5-1, 066	B
Pipe trenches	Structural support	Concrete	Air –outdoor Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5-1, 043	E, 1
Pipe trenches	Structural support	Concrete	Soil	Cracking Loss of bond Loss of material	Structures Monitoring	III.A3.TP-27	3.5-1, 065	B
Pipe trenches	Structural support	Concrete	Soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring	III.A3.TP-29	3.5-1, 067	B
Pipe whip restraints	Pipe whip restraint	Carbon steel	Air – outdoor	Loss of material	Structures Monitoring	III.B5.TP-43	3.5-1, 092	B
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	B

Table 3.5.2-18: Yard Structures — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel cable tray and conduits supports	Structural support	Carbon steel Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.T-25	3.5-1, 089	A
Steel cable trays and conduits	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.B2.TP-43	3.5-1, 092	D
Steel cable trays and conduits	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion	III.B2.T-25	3.5-1, 089	C
Stop logs	Flood barrier	Aluminum	Air – outdoor	Loss of material Cracking	Structures Monitoring	III.B5.T-37b	3.5-1, 100	D
Storm drains and catch basins	Flood barrier	Concrete	Air – outdoor Water-flowing or standing	Cracking Loss of bond Loss of material	Structures Monitoring	III.A6.TP-220	3.5-1, 050	E, 1
TPCW basket strainer monorail	Structural support	Carbon steel	Air – outdoor	Cumulative fatigue damage	TLAA - Section 4.7.6, Crane Load Cycle Limit	VII.B.A-06	3.3-1, 001	A
TPCW basket strainer monorail	Structural support	Carbon steel	Air – outdoor	Loss of material Deformation Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-07	3.3-1, 052	A

Table 3.5.2-18:Yard Structures — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
TPCW basket strainer monorail bolting	Structural support	Carbon steel	Air – outdoor	Loss of preload Loss of material Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	VII.B.A-730	3.3-1, 199	A
Transmission towers	Structural support	Carbon steel Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring	III.A3.TP-302	3.5-1, 077	B

Notes for Table 3.5.2-18

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant-Specific Notes for Table 3.5.2-18

1. The Structures Monitoring AMP will be used to manage cracking due to expansion from reaction with aggregates.

3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS

3.6.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.5, Electrical and Instrumentation and Controls, as being subject to AMR.

3.6.2 Results

Table 3.6.2-1, Electrical Commodities Summary of Aging Management Evaluation, presents the results of aging management reviews and the NUREG-2191 comparison for electrical commodities.

3.6.2.1 Materials, Environments, Aging Effects Requiring Management, and Aging Management Programs

The following sections list the materials, environments, aging effects requiring management, and aging management programs for electrical commodities subject to aging management review. Programs are described in Appendix B. Further details are provided in Table 3.6.2-1.

Materials

Electrical commodities subject to aging management review are constructed of the following materials.

- Aluminum
- Copper
- Cement
- Galvanized metals
- Insulation material – various organic polymers
- Porcelain
- Steel and steel alloys
- Stainless steel
- Various metals used for bus and electrical connections

Environment

Electrical commodities subject to aging management review are exposed to the following environments.

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

- Heat and air
- Moisture and air
- Radiation and air
- Significant moisture

Aging Effects Requiring Management

The following aging effects associated with electrical commodities require management.

- Increased resistance of connection
- Loss of material
- Reduced insulation resistance (IR)

Aging Management Programs

The following aging management programs will manage the effects of aging on electrical commodities.

- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.38)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits (B.2.3.39)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.40)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.41)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.42)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.43)
- High-Voltage Insulators (B.2.3.44)
- Boric Acid Corrosion (B.2.3.4)

3.6.2.2 AMR Results for Which Further Evaluation is recommended by the GALL Report

NUREG-2192 indicates that further evaluation is necessary for certain aging effects and programs identified in Section 3.6.2.2 of NUREG-2192. The following sections, numbered corresponding to the discussions in NUREG-2192, present the Turkey Point approach to these areas requiring further evaluation. Programs are described in Appendix B. Italicized text is taken directly from NUREG-2192.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

The AMRs and the AMPs applicable to the electrical and I&C components are described and evaluated in Chapter VI of the GALL-SLR Report.

The SLRA should provide sufficient information for the NRC reviewer to confirm that the specific SLRA AMR item and the associated SLRA AMP are consistent with the cited GALL-SLR Report AMR item. The reviewer should then confirm that the SLRA AMR item is consistent with the GALL-SLR Report AMR item to which it is compared.

When crediting a different AMP than recommended in the GALL-SLR Report, the reviewer should confirm that the alternate AMP is valid to use for aging management and will be capable of managing the effects of aging as adequately as the AMP recommended by the GALL-SLR Report.

Electrical equipment environmental qualification (EQ) analyses are TLAAs as defined in 10 CFR 54.3. TLAAs are evaluated in accordance with 10 CFR 54.21(c) and addressed in Section 4.4. EQ components are subject to replacement based on a qualified life, and therefore, are not subject to aging management review.

3.6.2.2.2 Reduced Insulation Resistance Due to Age Degradation of Cable Bus Arrangements Caused by Intrusion of Moisture, Dust, Industrial Pollution, Rain, Ice, Photolysis, Ohmic Heating and Loss of Strength of Support Structures and Louvers of Cable Bus Arrangements Due to General Corrosion and Exposure to Air Outdoor

Reduced insulation resistance due to age degradation of cable bus caused by intrusion of moisture, dust, industrial pollution, rain, ice, photolysis (for ultraviolet sensitive material only), ohmic heating and loss of strength of support structures, covers or louvers of cable bus arrangements due to general corrosion or exposure to air outdoor could occur in cable bus assemblies. Cable bus is a variation of metal enclosed bus (MEB) which is similar in construction to an MEB, but instead of segregated or nonsegregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both the cable bus and enclosures are not sealed against intrusion of dust, industrial pollution, moisture, rain, and ice and therefore may introduce debris into the internal cable bus assembly.

Consequently, cable bus construction and arrangements are such that it may not readily fall under a specific GALL-SLR Report AMP (e.g., GALL-SLR Report AMP XI.E1 and AMP XI.E4).GALL-SLR Report AMP XI.E1 calls for a visual inspection of accessible insulated cables and connections subject to an adverse localized environment which may not be applicable to cable bus due to inaccessibility or applicability of the aging mechanisms and effects. GALL-SLR Report AMP XI.E4 includes tests and inspections of the internal and external portions of the MEB. The

MEB internal and external inspections and tests may not be applicable to cable bus aging mechanisms and effects. Therefore, the GALL-SLR Report recommends cable bus aging mechanisms and effects be evaluated as a plant-specific further evaluation. The evaluation includes associated AMPs: AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," and AMP XI.S6, "Structures Monitoring." Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

The discussion in NUREG-2192 addresses aging effects on cable bus. Cable bus is a variation on metal enclosed bus (MEB) which is similar in construction to an MEB, but instead of segregated or non-segregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus is not utilized at Turkey Point, and therefore, NUREG-2192 aging effects are not applicable. Section 2.5.1.3 contains additional information on cable bus.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload for Transmission Conductors, Switchyard Bus, and Connections

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL-SLR Report recommends further evaluation of a plant-specific AMP to demonstrate that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of the SRP-SLR).

Transmission conductors are uninsulated, stranded electrical cables used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as active disconnect switches, power circuit breakers, and transformers and passive switchyard bus. The transmission conductor commodity group includes the associated fastening hardware but excludes the high-voltage insulators. Major active equipment assemblies include their associated transmission conductor terminations.

Transmission conductors are subject to aging management review if they are necessary for recovery of offsite power following an SBO event. At Turkey Point, transmission conductors from the 240-kV switchyard to the Units 3 and 4 start-up transformers support SBO recovery. Other transmission conductors are not subject to aging management review since they do not perform or support SLR intended functions.

Switchyard bus is the uninsulated, unenclosed, rigid electrical conductor or pipe used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as active disconnect switches and passive transmission conductors. Switchyard bus includes the hardware used to secure the bus to high-voltage insulators.

Switchyard bus is subject to aging management review if it is necessary for recovery of offsite power following an SBO event. At Turkey Point, switchyard bus from the 240-kV switchyard breakers to the 240-kV transmission conductors support SBO recovery. Other switchyard bus is not subject to aging management review since it does not perform or support SLR intended functions.

Loss of Material (Wear)

Wind loading can cause transmission conductor vibration, or sway. Wind loading that can cause a transmission line and insulators to vibrate is considered in the design and installation of transmission conductors at Turkey Point such that they are not susceptible to vibration or excessive sway. As a result, loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not aging effects requiring management because they are precluded by design. A review of industry OE and NRC generic communications related to the aging of transmission conductors confirmed that no additional aging effects exist beyond those previously identified. A review of plant-specific OE did not identify any unique aging effects for transmission conductors.

Switchyard bus is connected to active equipment by short sections of flexible conductors. As a result, the rigid bus does not vibrate because it is supported by insulators and ultimately by static, structural components such as concrete footings and structural steel. The flexible conductors withstand the minor vibrations associated with the active switchyard components and are part of the switchyard bus commodity group. Accordingly, vibration is not applicable for switchyard bus because flexible conductors connecting switchyard bus to active components eliminate the potential for vibration.

Therefore, loss of material due to wear of transmission conductors and switchyard bus is not an aging effect requiring management at Turkey Point.

Loss of Conductor Strength (Corrosion)

This aging effect applies to aluminum conductor steel reinforced (ACSR) transmission conductors. The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR transmission conductors, degradation begins as a loss of zinc from the galvanized steel core wires.

Corrosion in ACSR conductors is a very slow-acting aging mechanism with the corrosion rates depending largely on air quality. Air quality factors include suspended particle chemistry, sulfur dioxide (SO_2) concentration, precipitation, fog chemistry, and meteorological conditions. Air quality in rural areas, such as the area surrounding Turkey Point, generally contains low concentrations of suspended particles and SO_2, which minimizes the corrosion rate. There are no industries within the 0–5-mile radius of Turkey Point, with approximately one-half of the total area within the 0–5-mile radius being formed by the coastal waters in Biscayne Bay. Tests performed by Ontario Hydro showed a 30% loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion.

The high-sides of Turkey Point Units 3 and 4 startup transformers are connected to the 240-kV switchyard via overhead transmission lines. The Turkey Point transmission conductors subject to aging management review are 1431 thousands of circular mils (MCM) ACSR. This specific conductor construction type was included in the Ontario Hydroelectric test, so the results of this test are representative of the Turkey Point 240-kV overhead transmission conductors.

There is a set percentage of composite conductor strength established at which a transmission conductor is replaced. As illustrated below, there is ample strength margin to maintain the SLR intended function of these Turkey Point transmission conductors through the SPEO.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum 60% of the ultimate conductor strength. The NESC also specifies the maximum tension to which a conductor must be designed in order to withstand heavy load requirements (consideration of ice, wind and temperature). These requirements were reviewed for the specific transmission conductors included in the scope of SLR for Turkey Point. Evaluation of the conductor type with the smallest ultimate strength margin (4/0 ACSR, 6/1) in the NESC illustrates the conservative nature of the design of transmission conductors.

The ultimate strength and the NESC heavy load tension requirements of 4/0 (212 MCM) ACSR, 6/1 are 8350 lbs. and 2761 lbs. respectively. The heavy load tension is 33% of the ultimate strength (2761 lbs/8350 lbs), which is well within the NESC criterion of 60%. The actual margin between the NESC heavy load and the ultimate strength is 5589 lb.; i.e., there is an ultimate strength margin of 67%. The Ontario Hydroelectric study showed a 30% loss of composite conductor strength in an 80-year-old conductor. In the case of the 4/0 ACSR transmission conductor, a 30% loss of ultimate strength would mean the heavy load tension is 47% of the ultimate strength (2761 lbs/5845 lbs), which is still within the NESC criterion of 60%. The actual margin for an 80-year 4/0 ACSR, 6/1 transmission conductor between the NESC heavy load and the aged ultimate strength would be 3084 lb.; i.e., there would still be an aged ultimate strength margin of 53%.

The 4/0 ACSR conductor type has the lowest initial design margin of transmission conductors included in the review. Also, the ACSR transmission conductor in the Ontario Hydroelectric study was an 80-year-old specimen which corresponds to the

Turkey Point SPEO. The above summary demonstrates with reasonable assurance that transmission conductors will have ample strength through the SPEO. A review of industry OE and NRC generic communications related to the aging of transmission conductors confirmed that no additional aging effects exist beyond those previously identified. A review of plant-specific OE did not identify any unique aging effects for transmission conductors.

Therefore, loss of conductor strength is not an aging effect requiring management for transmission conductors at Turkey Point.

Increased Connection Resistance (Corrosion)

Increased connection resistance due to surface oxidation is an applicable aging effect, but it is not significant enough to cause a loss of intended function. The aluminum, steel, and steel alloy components in the switchyard are exposed to precipitation, but these components do not experience any appreciable aging effects in this environment, except for minor oxidation, which does not impact the ability of the connections to perform their intended function. At Turkey Point, switchyard connection surfaces are coated with an antioxidant compound (i.e., a grease-type sealant) prior to tightening the connection to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connections, thus minimizing the potential for corrosion. Based on site-specific and industry wide operating experience, this method of installation has proven to provide a corrosion-resistant low electrical resistance connection. In addition, Turkey Point periodically performs infrared inspections of the 240-kV switchyard connections to verify the integrity of the connections. The infrared inspections of the 240-kV switchyard connections verify the effectiveness of the connection design and site installation practices. These inspections and the absence of plant specific OE verifies that this aging effect is not significant for Turkey Point.

Therefore, increased connection resistance due to general corrosion resulting from oxidation of switchyard connection metal surfaces is not an aging effect requiring management at Turkey Point.

Increased Connection Resistance (Loss of Preload)

Increased connection resistance due to loss of pre-load (torque relaxation) for switchyard connections is not an aging effect requiring management. The Electric Power Research Institute (EPRI) license renewal tools do not list loss of pre-load as an applicable aging mechanism. The design of the transmission conductor and switchyard bus bolted connections precludes torque relaxation as confirmed by plant specific OE. A plant-specific review of OE did not identify any failures of switchyard connections. The design of switchyard bolted connections includes Bellville washers and an anti-oxidant compound (i.e., a grease-type sealant) to preclude connection degradation. The type of bolting plate and the use of Bellville washers is the industry standard to preclude torque relaxation. This design configuration, combined with the proper sizing of the conductors, eliminates the need to consider this aging mechanism. Therefore, increased connection resistance due to loss of pre-load on switchyard connections is not an aging effect requiring management.

For bolted connections between transmission conductors and switchyard bus, in-scope transmission conductors at Turkey Point are limited to the connections from the 240-kV switchyard to the Units 3 and 4 startup transformers used for recovery of offsite power following an SBO event. Routine inspections of the Turkey Point 240-kV switchyard and startup transformers include performing periodic infrared inspections of this power path to verify the integrity of the connections. These inspections and the absence of plant specific OE demonstrates that this aging effect is not significant for Turkey Point.

Therefore, increased connection resistance due to loss of pre-load of transmission conductor and switchyard bus connections is not an aging effect requiring management for Turkey Point.

There are no applicable aging effects that could cause a loss of the intended function of the transmission conductor connections and switchyard bus connections for the SPEO. Therefore, there are no aging effects requiring management for Turkey Point transmission conductors and switchyard bus connections.

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix A.2 of the SRP-SLR).

Quality Assurance provisions applicable to Subsequent license renewal are discussed in Appendix B.

3.6.2.2.5 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The Operating Experience process and acceptance criteria are described in Appendix B.

3.6.2.3 Time-Limited Aging Analysis

The only TLAAs identified for electrical commodities are evaluations for environmental qualification (EQ) associated with 10 CFR 50.49. The EQ TLAAs are evaluated in Section 4.4.

3.6.3 Conclusion

Electrical commodities that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). Aging management programs selected to manage aging effects for electrical commodities are identified in Section 3.6.2.1 and in the following tables. A description of aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be effectively managed.

Based on the demonstrations provided in Appendix B, the effects of aging associated with electrical commodities will be managed such that the intended functions will be maintained consistent with the current licensing basis during the SPEO.

Table 3.6-1
Summary of Aging Management Evaluations for Electrical Commodities

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 001	Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of various polymeric and metallic materials in plant areas subject to a harsh environment (i.e., loss of coolant accident (LOCA), high energy line break (HELB), or post LOCA environment or; An 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 Electrical Equipment,” for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See Chapter X.E1, “Environmental Qualification (EQ) of Electric Components,” of this report for meeting the requirements of 10 CFR 54.21(c)(1)(i)-(iii).	Yes, TLAA (SRP-SLR Section 3.6.2.2.1)	Consistent with NUREG-2191. EQ equipment is not subject to aging management review because the equipment is subject to replacement based on a qualified life. EQ analyses are evaluated as TLAAs in Section 4.4. See Section 3.6.2.2.1 for further evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 002	High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor	Loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	AMP XI.E7, "High-Voltage Insulators"	No	Consistent with NUREG-2191. The High-Voltage Insulators AMP will manage these aging effects.
3.6-1, 003	High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination	AMP XI.E7, "High-Voltage Insulators"	No	Consistent with NUREG-2191. The High-Voltage Insulators AMP will manage these aging effects.
3.6-1, 004	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of conductor strength due to corrosion	A plant-specific aging management program is to be evaluated for ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to Turkey Point. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 005	Transmission connectors composed of aluminum; steel exposed to air – outdoor	Increased resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to Turkey Point. See Section 3.6.2.2.3 for further evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 006	Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air – outdoor	Loss of material due to wind induced abrasion; Increased resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to Turkey Point. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 007	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of material due to wind-induced abrasion	A plant-specific aging management program is to be evaluated for ACAR and ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to Turkey Point. See Section 3.6.2.2.3 for further evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 008	Electrical insulation for electrical cables and connections (including terminal blocks, etc.) composed of various organic polymers (e.g., EPR (ethylene propylene rubber), SR (silicone rubber), EPDM (ethylene propylene diene monomers), XLPE (cross-linked polyethylene)) 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 EQ Requirements program will manage the effects of aging. This program includes inspection of non-EQ electrical and I&C penetration cables and connections. Turkey Point EQ electrical and I&C penetration assemblies are covered under the EQ program.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 009	Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	No	Consistent with NUREG-2191. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP will manage these aging effects. This AMP includes review of calibration results or surveillance findings for instrumentation circuits.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 010	Electrical conductor insulation for inaccessible power, instrumentation, and control cables (e.g., installed in duct bank, buried conduit or direct buried) composed of various organic polymers 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. The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements XI.E3A AMP, the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements XI.E3B AMP, or the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements XI.E3C AMP will manage these aging effects. AMPs include inspection of manholes and de-watering activities as required.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 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, 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. NUREG-2191 aging effects are not applicable because metal enclosed bus is not within the scope of SLR at Turkey Point.
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	Not applicable. NUREG-2191 aging effects are not applicable because metal enclosed bus is not within the scope of SLR at Turkey Point.
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	Not applicable. NUREG-2191 aging effects are not applicable because metal enclosed bus is not within the scope of SLR at Turkey Point.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 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. NUREG-2191 aging effects are not applicable because metal enclosed bus is not within the scope of SLR at Turkey Point.
3.6-1, 015	Metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to pitting, crevice corrosion	AMP XI.E4, “Metal Enclosed Bus” or AMP XI.S6, “Structures Monitoring”	No	Not applicable. NUREG-2191 aging effects are not applicable because metal enclosed bus is not within the scope of SLR at Turkey Point.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 016	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, uncontrolled	Increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply)	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation.	No	Not applicable. The electrical screening process determined that there are no safety related fuses, or non-safety related fuses which support safety related equipment in performing its intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at Turkey Point are not subject to aging management review.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 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. The electrical screening process determined that there are no safety related fuses, or non-safety related fuses which support safety related equipment in performing its intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at Turkey Point are not subject to aging management review.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 018	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, controlled or uncontrolled	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/ manipulation or vibration	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue caused by frequent fuse removal/manipulation or vibration.	No	Not applicable. The electrical screening process determined that there are no safety related fuses, or non-safety related fuses which support safety related equipment in performing its intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at Turkey Point are not subject to aging management review.
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 EQ Requirements AMP will manage the effects of aging.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 020	Electrical connector contacts for electrical connectors composed of various metals used for electrical contacts exposed to air with borated water leakage	Increased electrical resistance of connection due to corrosion of connector contact surfaces caused by intrusion of borated water	AMP XI.M10, “Boric Acid Corrosion”	No	Consistent with NUREG-2191. The Boric Acid Corrosion AMP will manage the effects of aging.
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	NUREG-2191 aging effects are not applicable to Turkey Point. See Section 3.6.2.2.3 for further evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 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. The electrical screening process determined that there are no safety related fuses, or non-safety related fuses which support safety related equipment in performing its intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at Turkey Point are not subject to aging management review.
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. Metal enclosed bus is not within the scope of SLR at Turkey Point.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 024	Metal enclosed bus: external surface of enclosure assemblies. Steel air – indoor controlled	None	None	No	Not applicable. Metal enclosed bus is not within the scope of SLR at Turkey Point.
3.6-1, 025	There is no 3.6-1, 025 in NUREG-2192.				
3.6-1, 026	There is no 3.6-1, 026 in NUREG-2192.				
3.6-1, 027	Cable bus: external surface of enclosure assemblies galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Not applicable. Cable bus is not utilized at Turkey Point.
3.6-1, 028	There is no 3.6-1, 028 in NUREG-2192.				

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 029	Cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to degradation caused thermal/ thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. Cable bus is not utilized at Turkey Point.
3.6-1, 030	Cable bus: external surface of enclosure assemblies composed of steel exposed to air – indoor uncontrolled or air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. Cable bus is not utilized at Turkey Point.
3.6-1, 031	Cable bus external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. Cable bus is not utilized at Turkey Point.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not applicable. Cable bus is not utilized at Turkey Point.

Table 3.6.2-1
Electrical Commodities — Summary of Aging Management Evaluation

Table 3.6.2-1: Electrical Commodities — Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Cable connections (metallic parts)	Electrical Continuity	Various metals used for electrical contacts	Air – indoor controlled Air - indoor uncontrolled Air – outdoor	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	VI.A.LP-30	3.6-1, 019	A
Electrical conductor insulation for inaccessible instrumentation and control cables (e.g., installed in duct bank, buried conduit or direct buried)	Insulate (electrical)	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	VI.A.LP-35b	3.6-1, 010	A
Electrical conductor insulation for inaccessible low-voltage cables – typical operating voltage of < 1 kV but no greater than 2 kV (e.g., installed in duct bank, buried conduit or direct buried)	Insulate (electrical)	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	VI.A.LP-35c	3.6-1, 010	A

Table 3.6.2-1: Electrical Commodities — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical conductor insulation for inaccessible medium-voltage cables -typical operating range of 2 kV to 35 kV (e.g., installed in duct bank, buried conduit or direct buried)	Insulate (electrical)	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	VI.A.LP-35a	3.6-1, 010	A
Electrical connector contacts for electrical connectors	Electrical Continuity	Various metals used for electrical contacts	Air with borated water leakage	Increased electrical resistance of connection	Boric Acid Corrosion	VI.A.LP-36	3.6-1, 020	A
Electrical insulation for electrical cables and connections (including terminal blocks, etc.)	Insulate (electrical)	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	VI.A.LP-33	3.6-1, 008	A

Table 3.6.2-1: Electrical Commodities — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor electrical insulation resistance (IR)	Insulate (electrical)	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	VI.A.LP-34	3.6-1, 009	A
High-voltage electrical insulators	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement	Air – outdoor	Loss of material	High-Voltage Insulators	VI.A.LP-32	3.6-1, 002	A
High-voltage electrical insulators	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement	Air – outdoor	Reduced electrical insulation resistance	High-Voltage Insulators	VI.A.LP-28	3.6-1, 003	A
Switchyard bus and connections	Electrical Continuity	Aluminum; copper; stainless steel; galvanized steel	Air – outdoor	None	None	VI.A.LP-39	3.6-1, 006	I
Transmission conductors	Electrical Continuity	Aluminum	Air – outdoor	None	None	VI.A.LP-46	3.6-1, 021	I

Table 3.6.2-1: Electrical Commodities — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Transmission conductors	Electrical Continuity	Aluminum; steel	Air – outdoor	None	None	VI.A.LP-48	3.6-1, 005	I
Transmission conductors	Electrical Continuity	Aluminum; steel	Air – outdoor	None	None	VI.A.LP-38	3.6-1, 004	I
Transmission conductors	Electrical Continuity	Aluminum; steel	Air – outdoor	None	None	VI.A.LP-47	3.6-1, 007	I
Electrical equipment subject to 10 CFR 50.49 EQ requirements	Insulate (electrical)	Various polymeric materials	Areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment Adverse localized environment (e.g., temperature, radiation, or moisture)	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	Environmental Qualification of Electric Equipment	VI.B.L-05	3.6-1, 001	A

Table 3.6.2-1: Electrical Commodities — Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical equipment subject to 10 CFR 50.49 EQ requirements	Electrical Continuity	Various metallic materials	Areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment Adverse localized environment (e.g., temperature, radiation, or moisture)	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	Environmental Qualification of Electric Equipment	VI.B.L-05	3.6-1, 001	A

Notes for Table 3.6.2-1

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

4.0 TIME-LIMITED AGING ANALYSES

This section presents descriptions of the Time-Limited Aging Analyses (TLAAs) and exemptions based on TLAAs for Turkey Point Units 3 and 4 in accordance with 10 CFR 54.3(a) and 10 CFR 54.21(c). Section 4 is divided into Sections 4.1 through 4.7. A number of non-proprietary and proprietary reference documents have been included in Enclosures 4 and 5, respectively, to FPL letter L-2018-004, and are cited, where applicable, throughout this section.

Section 4.1 provides the 10 CFR Part 54 definition and requirements for TLAAs and summarizes the process used for identifying and evaluating TLAAs and exemptions.

Subsequent sections describe the evaluation of TLAAs within the following categories.

- Section 4.2, Reactor Vessel Neutron Embrittlement Analysis
- Section 4.3, Metal Fatigue
- Section 4.4, Environmental Qualification (EQ) of Electrical Equipment
- Section 4.5, Concrete Containment Tendon Prestress
- Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue
- Section 4.7, Other Plant-Specific TLAAs

4.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

10 CFR 54.21(c) requires an evaluation of time-limited aging analyses be provided as part of the application for a renewed license. Time-limited aging analyses are defined in 10 CFR 54.3 as those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);

(2) Consider the effects of aging;

(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;

(4) Were determined to be relevant by the licensee in making a safety determination;

(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b); and

(6) Are contained or incorporated by reference in the CLB.

4.1.1 Time-Limited Aging Analyses Identification Process

The process used to identify the PTN specific time-limited aging analyses is consistent with the guidance provided in NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal" (Reference 4.1.6.1), NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report" (Reference 4.1.6.2) and NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" (Reference 4.1.6.3).

The current licensing basis (CLB) 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
- Technical Requirements Manual
- Docketed licensing correspondence
- NRC Safety Evaluation Reports (SERs)
- Design Basis Documents (DBDs)
- Fire Protection Plan/Hazards Analyses
- Westinghouse design analyses and reports
- Vendor design analyses and reports
- Environmental Qualification documentation packages
- Design specifications
- 10 CFR 50.12 Exemption Requests

Each potential TLAA was reviewed against the six criteria of 10 CFR 54.3(a). Those that met all six criteria were identified as TLAAs which require evaluation for the subsequent period of extended operation (SPEO).

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 these have been identified as TLAAs for PTN. Those with a "Yes" entry apply to PTN and the SLRA section where they are evaluated is provided. Those with a "No" entry were determined to not apply to PTN either because they are associated with design features not employed at PTN or because no analyses were identified in that category that meet all six TLAA criteria.

As an additional check, several recent license renewal applications and requests for additional information (RAIs) were also reviewed to determine if a TLAA evaluated for another plant was applicable to PTN. The TLAAs identified in these LRAs were reviewed to determine if PTN had the same or a similar TLAA that needed to be evaluated for the SPEO. No new or additional TLAAs were identified. The original PTN LRA and associated RAIs and responses were reviewed to ensure TLAAs previously evaluated are adequately addressed.

4.1.2 Evaluation of Turkey Point Time-Limited Aging Analyses

Each part of Section 4 evaluates one or more related TLAAs. Information is provided using the following definitions:

TLAA Description:

A description of the CLB analysis that has been identified as a TLAA, including a description of the aging effect evaluated, the time-limited variable used in the analysis, and its basis.

TLAA Evaluation:

An evaluation of the TLAA for the SPEO, including information associated with 80 years of operation for comparison with the information used in the TLAA that considered 60 years of operation, provides the basis for the TLAA disposition. The three disposition categories from 10 CFR 54.21 are shown below in Section 4.1.3.

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 SPEO;

(ii) The analyses have been projected to the end of the SPEO; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the SPEO.

One of these three methods were used to disposition each TLAA identified for PTN. The disposition methods used are described in each TLAA evaluation section.

4.1.4 Summary of Results

Several categories of TLAAs were identified for PTN. The TLAAs are grouped together by affected component type and aging effect analyzed, as shown in the TLAA Summary in Table 4.1-2. The table includes a reference to the applicable section of the SLRA that evaluates each TLAA. SLRA Sections 4.2 through 4.7 provide descriptions and evaluations of the TLAAs and classify their disposition.

4.1.5 Identification and Evaluation of Exemptions

10 CFR 54.21(c)(2) states: A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on TLAAs as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the SPEO. A search of docketed licensing correspondence, the operating license, and the Updated Final Safety Analysis Report (UFSAR) identified the active exemptions currently in effect pursuant to 10 CFR 50.12. These exemptions were then reviewed to determine whether the exemption was based on a TLAA. No 10 CFR 50.12 exemptions involving a TLAA as defined in 10 CFR 54.3 were identified for Turkey Point Units 3 and 4.

4.1.6 References

4.1.6.1 NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal, March 2017.

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

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

Table 4.1-1
Review of Generic TLAAs in NUREG-2192, Tables 4.1-2 and 4.7-1

NUREG-2192 Example TLAA	Applies to Turkey Point	SLRA Section
NUREG-2192, Table 4.1-2 – Potential TLAAs		
Reactor Vessel Neutron Embrittlement	Yes	4.2
Metal Fatigue[1]	Yes	4.3
Environmental Qualification (EQ) of Electrical Equipment	Yes	4.4
Concrete Containment Tendon Prestress	Yes	4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	4.6
NUREG-2192, Table 4.7-1 – Examples of Potential Plant-Specific TLAA Topics		
Reactor pressure vessel underclad cracking	Yes	4.3.4
Leak-before-break	Yes	4.7.3 and 4.7.4
Reactor coolant pump flywheel fatigue crack growth	Yes	4.3.5
Response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification"	Yes[2]	4.3
Response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Cooling Systems"	Yes[2]	4.3
Fatigue of cranes (crane cycle limits)	Yes	4.7.6
Fatigue of the spent fuel pool liner	No[3]	NA
Corrosion allowance calculations	No[4]	NA
Flaw growth due to stress corrosion cracking	No[5]	NA
Predicted lower limit	Yes[6]	4.5

Notes for Table 4.1-1

1. High energy line break is not a TLAA for PTN, and as such is not included with metal fatigue.
2. Addressed as part of the fatigue evaluation.
3. There is no fatigue analysis for the PTN spent fuel pool liner.
4. No metal corrosion allowance analyses applicable to 60-year operation were identified.
5. No flaw growth due to stress corrosion analyses applicable to 60-year operation were identified.
6. Addressed as part of the containment tendon prestress TLAAs.

Table 4.1-2
Summary of Results — Turkey Point TLAAs

TLAA Description	Resolution 10 CFR 54.21(c)(1) Section	Section
REACTOR VESSEL NEUTRON EMBRITTLEMENT		4.2
Neutron Fluence Projections	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.2.1
Pressurized Thermal Shock	(ii) projected to the end of the SPEO	4.2.2
Upper-Shelf Energy	(ii) projected to the end of the SPEO	4.2.3
Adjusted Reference Temperature	(ii) projected to the end of the SPEO	4.2.4
Pressure-Temperature Limits and LTOP Setpoints	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.2.5
METAL FATIGUE		4.3
Metal Fatigue of Class 1 Components	(i) remains valid for the SPEO	4.3.1
Metal Fatigue of Piping Components	(i) remains valid for the SPEO	4.3.2
Environmentally Assisted Fatigue	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.3.3
Reactor Vessel Underclad Cracking	(ii) projected to the end of the SPEO	4.3.4
Reactor Coolant Pump Flywheel	(i) remains valid for the SPEO	4.3.5
ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL EQUIPMENT	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.4
CONCRETE CONTAINMENT TENDON PRESTRESS	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.5
CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE	(i) remains valid for the SPEO	4.6

Table 4.1-2
Summary of Results — Turkey Point TLAAs (Continued)

TLAA Description	Resolution 10 CFR 54.21(c)(1) Section	Section
OTHER PLANT-SPECIFIC TLAAS		4.7
Bottom-Mounted Instrumentation Thimble Tube Wear	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.7.1
Emergency Containment Cooler Tube Wear	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.7.2
Leak-Before-Break Analysis for Reactor Coolant System Piping	(ii) projected to the end of the SPEO	4.7.3
Leak-Before-Break Analysis for Class 1 Auxiliary Piping	(ii) projected to the end of the SPEO	4.7.4
Code Case N-481 Reactor Coolant Pump Integrity Analysis	(ii) projected to the end of the SPEO	4.7.5
Crane Load Cycle Limit	(i) remains valid for the SPEO	4.7.6

4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR Part 50, Appendices G and H. The PTN Reactor Vessel Material Surveillance aging management program (AMP) is described in SLRA Section B.2.3.19. The ferritic materials of the reactor vessel are subject to embrittlement due to high energy (E > 1.0 MeV) neutron exposure. Embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). Since these neutron embrittlement analyses are calculated based on plant life, they are identified as TLAAs. This group of TLAAs concerns the effect of irradiation embrittlement on the belt-line regions of the Turkey Point Units 3 and 4 reactor vessels, and how this mechanism affects analyses that provide operating limits or address regulatory requirements.

Fracture toughness (indirectly measured in foot-pounds of absorbed energy in a Charpy impact test) is temperature dependent in ferritic materials. An initial nil-ductility reference temperature (RT_{NDT}) is associated with the transition from ductile to brittle behavior and is determined for vessel materials through a combination of Charpy and drop-weight testing. Toughness increases with temperature up to a maximum value called the “upper-shelf energy,” or USE. Neutron embrittlement results in a decrease in the USE (maximum toughness) of the reactor vessel steels.

To reduce the potential for brittle fracture during reactor vessel operation, changes in material toughness as a function of neutron radiation exposure (fluence) are accounted for through the use of operating P-T limits that are included in the PTN Technical Specifications. The P-T limits account for the decrease in material toughness of the reactor vessel beltline materials that are predicted to receive a cumulative neutron exposure of 1.0×10^{17} neutrons/cm^2 or more during the licensed life of the plant. Since the cumulative neutron fluence will increase during the SPEO, a review is required to determine if any additional components will exceed the cumulative neutron fluence threshold value and require evaluation for neutron embrittlement. The materials that exceed this threshold are referred to as the extended beltline materials.

Based on the projected drop in toughness for each beltline material as a result of exposure to the predicted fluence values, USE calculations are performed to determine if the components will continue to have adequate fracture toughness at the end of the license to meet the required minimums. P-T limit curves are generated to provide minimum temperature limits that must be achieved during operations prior to applications of specified reactor vessel pressures. The P-T limit curves are based upon the RT_{NDT} and ΔRT_{NDT} values computed for the licensed operating period along with appropriate margins.

The reactor vessel material ΔRT_{NDT} and USE values, calculated on the basis of neutron fluence, are part of the current licensing basis and support safety determinations. Therefore, these calculations have been identified as TLAAs. The following TLAAs related to neutron embrittlement are evaluated in the SLRA sections listed below:

- Neutron Fluence Projections (4.2.1)
- Pressurized Thermal Shock (4.2.2)
- Upper-Shelf Energy (4.2.3)
- Adjusted Reference Temperature (4.2.4)
- Pressure-Temperature (P-T) Limits and LTOP setpoints (4.2.5)

4.2.1 Neutron Fluence Projections

TLAA Description

Neutron fluence is the term used to represent the cumulative number of neutrons per unit area 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 fluence projections used as inputs to the current 60-year neutron embrittlement analyses were developed using discrete ordinates transport fluence methodology. The fluence projections for 60 years were updated for the extended power uprate (EPU) and provided in the EPU license amendment requests (References 4.2.6.10 and 4.2.6.11) and approved by the NRC in the EPU license amendments (Reference 4.2.6.12). Fluence calculations are periodically verified and updated based on in-vessel surveillance capsules as part of the Reactor Vessel Material Surveillance AMP (Section B.2.3.19). The current reactor vessel surveillance capsule withdrawal schedule is provided in UFSAR Table 4.4-2. These projections predicted the neutron fluence expected to occur during 48 Effective full Power Years (EFPY) of plant operation. At the time the projections were prepared, 48 EFPY was considered to represent the amount of power to be generated over 60 years of plant operation, assuming a 60-year average capacity factor of 80 percent. These fluence projections have been identified as a TLAA. The fluence projections are also inputs to additional TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

The first step in updating fluence projections for 80 years is to update the EFPY projections that are based upon actual unit operating history and upon a conservative capacity factor estimate for future cycles through the end of the SPEO. The information used to develop the EFPY projections is summarized below.

<u>EFPY Projections</u>

The 80-year EFPY Projections are the sum of the accumulated EFPYs and the future EFPYs accrued through the end of the SPEO at an estimated capacity factor. Accumulated EFPYs for Turkey Point Units 3 and 4 as of June 1, 2017, are 33.16 and 33.23, respectively. For future cycles through the end of the SPEO, the EFPYs were calculated using a conservative estimate for capacity factor of 100 percent. The summation of the two values was rounded up to the next whole year. Based on this approach, the bounding 80-year EFPYs for Turkey Point Units 3 and 4 is 72 EFPY.

Fluence Projections

For subsequent license renewal, updated fluence projections based upon 72 EFPY were prepared for use as inputs in the neutron embrittlement analyses prepared for 80 years of operation (end of the SPEO).

Fluence values applicable for 80 years of operation were calculated for each PTN reactor vessel beltline and extended beltline material (Reference 4.2.6.13). The analysis methods used to calculate the predicted 80-year PTN vessel fluence values satisfy the requirements set forth in Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence" (Reference 4.2.6.1). These methodologies have been approved by the U.S. Nuclear Regulatory Commission (NRC) and are described in detail in WCAP-14040-A (Reference 4.2.6.2) and WCAP-16083-NP-A (Reference 4.2.6.3).

In accordance with 10 CFR Part 50, Appendix H, any materials exceeding 1.0 x 10^{17} n/cm^2 (E > 1.0 MeV) must be monitored to evaluate changes in their fracture toughness. Reactor vessel materials that are not traditionally thought of as being plant limiting were evaluated to determine their cumulative fluence values at 72 EFPY. Therefore, fluence calculations were performed for the Turkey Point Units 3 and 4 reactor pressure vessel nozzle and shell forgings, and inlet nozzle-to-nozzle shell welds, outlet nozzle-to-nozzle shell welds, nozzle shell forging-to-intermediate shell forging circumferential welds, intermediate shell forging-to-lower shell forging circumferential welds, and lower shell forging-to-bottom head circumferential welds to determine if they will exceed 1.0 x 10^{17} n/cm^2 (E > 1.0 MeV) at 72 EFPY. The materials that exceed this threshold are referred to as the extended beltline materials.

Table 4.2.1-1 summarizes the results of the fluence projections to 72 EFPY for Turkey Point Units 3 and 4 beltline and extended beltline materials.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging due to fluence on the intended function will be adequately managed for the SPEO utilizing the Neutron Fluence Monitoring AMP (Section B.2.2.2) and the Reactor Vessel Material Surveillance AMP (Section B.2.3.19). Additionally, the fluence analyses have been projected to the end of the SPEO. They are to be used as inputs in the neutron embrittlement TLAA evaluations in the remainder of Section 4.2.

Table 4.2.1-1
Turkey Point Units 3 and 4
72 EFPY Neutron Fluence (E > 1.0 MeV) for Beltline and Extended Beltline Materials

Reactor Vessel Material	Neutron Fluence (E > 1.0 MeV)	
	Unit 3	Unit 4
Upper Shell Forging	1.13×10^{19}	1.15×10^{19}
Intermediate Shell Forging	1.08×10^{20}	1.08×10^{20}
Lower Shell Forging	9.86×10^{19}	9.81×10^{19}
Lower Head Ring (transition)	1.36×10^{17}	1.36×10^{17}
Inlet Nozzle	2.37×10^{17}	2.49×10^{17}
Outlet Nozzle	2.00×10^{17}	2.01×10^{17}
Inlet Nozzle Welds	2.37×10^{17}	2.49×10^{17}
Outlet Nozzle Welds	2.00×10^{17}	2.01×10^{17}
Upper Shell to Intermediate Shell Weld	1.13×10^{19}	1.15×10^{19}
Intermediate Shell to Lower Shell Weld	9.86×10^{19}	9.81×10^{19}
Lower Shell to Lower Head Ring Weld	1.36×10^{17}	1.36×10^{17}

4.2.2 Pressurized Thermal Shock

TLAA Description

The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock (PTS) events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature (RT_{PTS}) whenever a significant change occurs in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility. 10 CFR 50.61(b)(2) establishes screening criteria for RT_{PTS} at 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. The PTS analysis has been determined to be a TLAA.

TLAA Evaluation

The methods for calculating RT_{PTS} values are given in 10 CFR 50.61 and are consistent with the methods in Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials," (Reference 4.2.6.4) with the exception that Turkey Point Units 3 and 4 received the following exemptions from Appendix G to 10 CFR Part 50 and 10 CFR 50.61 (Reference 4.2.6.5).

The exemption from Appendix G to 10 CFR Part 50 replaces the required use of the existing Charpy V-notch and drop-weight-based methodology with an alternate methodology described in Topical Reports BAW-2308, Revisions 1-A and 2-A. This alternate methodology incorporates the use of fracture toughness test data for evaluating the integrity of the Linde 80 weld materials present in the Turkey Point Units 3 and 4 reactor pressure vessel beltline regions. The alternate methodology employs direct fracture toughness testing per the Master Curve methodology based on use of ASTM Standard Method E 1921 (1997 and 2002 editions), and ASME Code Case N-629. The exemption is required since Appendix G to 10 CFR Part 50 requires that for the pre-service or unirradiated condition, RT_{NDT} be evaluated by Charpy V-notch impact tests and drop weight tests according to the procedures in the ASME Code, Paragraph NB-2331.

The exemption from 10 CFR 50.61 uses an alternate methodology described in Topical Reports BAW-2308, Revisions 1-A and 2-A allowing direct fracture toughness test data for evaluating the integrity of the Linde 80 weld materials present in the Turkey Point Units 3 and 4 reactor vessels beltline regions, based on the use of ASTM E 1921 (1997 and 2002 editions) and ASME Code Case N-629. The exemption was required because the methodology for evaluating reactor vessel material fracture toughness in 10 CFR 50.61 requires that the pre-service or unirradiated condition be evaluated using Charpy V-notch impact tests and drop weight tests according to the procedures in the ASME Code, Paragraph NB-2331.

These exemptions address only those parts of the regulations (i.e., 10 CFR 50.61 and 10 CFR Part 50, Appendix G) which discuss the definition or use of unirradiated nil-ductility reference temperature, $RT_{NDT(U)}$, and its associated uncertainty, σ_{Δ}. Since these exemptions strictly deal with methodology they do not meet the exemption definition of 10 CFR 54.21(c)(2). All other requirements of 10 CFR 50.61 and 10 CFR Part 50, Appendix G are unchanged by this exemption.

These methods were used to calculate the RT_{PTS} for the PTN reactor vessel limiting materials at the end of the SPEO, 72 EFPY. The calculated RT_{PTS} values for Turkey Point Units 3 and 4 reactor vessels at 72 EFPY are shown in Tables 4.2.2-1 and 4.2.2-2, respectively.

The limiting RT_{PTS} value for Turkey Point Unit 3 reactor vessel shell forgings at 72 EFPY is [ ], which corresponds to the upper shell forging. The limiting RT_{PTS} value for the Unit 3 circumferentially-oriented welds at 72 EFPY is 261°F, which corresponds to the intermediate-to-lower shell circumferential weld (Heat # 71249).

The limiting RT_{PTS} value for Turkey Point Unit 4 reactor vessel shell forgings at 72 EFPY is [ ], which corresponds to the upper shell forging. The limiting RT_{PTS} value for the Unit 4 circumferentially-oriented welds at 72 EFPY is 261°F, which corresponds to the intermediate shell forging-to-lower shell circumferential weld (Heat # 71249).

As shown in Tables 4.2.2-1 and 4.2.2-2, the calculated RT_{PTS} values at 72 EFPY for the PTN reactor vessels are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the PTN reactor vessels during the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The PTS analyses have been projected to the end of the SPEO.

Table 4.2.2-1
RT_{PTS} Calculations for Turkey Point Unit 3 Extended Beltline Materials at 72 EFPY

Table 4.2.2-1: RT_{PTS} Calculations for Turkey Point Unit 3 Extended Beltline Materials at 72 EFPY

Reactor Vessel Material	Cu (Wt. %)	Ni (Wt. %)	$CF^{(1)}$ (°F)	Fluence (n/cm^2, E>1.0 MeV)	$FF^{(2)}$	$RT_{NDT(U)}^{(3)}$ (°F)	$\Delta RT_{NDT}^{(4)}$ (°F)	$\sigma_u^{(3)}$ (°F)	$\sigma_\Delta^{(5)}$ (°F)	Margin (°F)	RT_{PTS} (°F)	PTS Limit (°F)
Upper Shell (US) Forging	[ ]	0.68	[ ]	1.13×10^{19}	1.03	50	[ ]	0.0	[ ]	[ ]	[ ]	270
Intermediate Shell (IS) Forging	0.058	0.70	37.0	1.08×10^{20}	1.52	40	56	0.0	17.0	34.0	130	270
IS using Surveillance Data	0.058	0.70	6.9	1.08×10^{20}	1.52	40	10	0.0	5.2	10.5	61	270
Lower Shell (LS) Forging	0.079	0.67	51.0	9.86×10^{19}	1.51	30	77	0.0	17.0	34.0	141	270
LS using Surveillance Data	0.079	0.67	48.7	9.86×10^{19}	1.51	30	74	0.0	8.5	17.0	121	270
Lower Head Ring (transition)	[ ]	0.69	[ ]	1.36×10^{17}	0.13	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Inlet Nozzle 1	0.16	0.76	122.00	2.37×10^{17}	0.19	[ ]	23	[ ]	11.6	[ ]	[ ]	270
Inlet Nozzle 2	0.16	0.74	121.50	2.37×10^{17}	0.19	[ ]	23	[ ]	11.6	[ ]	[ ]	270
Inlet Nozzle 3	0.16	0.8	123.00	2.37×10^{17}	0.19	[ ]	23	[ ]	11.7	[ ]	[ ]	270
Outlet Nozzle 1	0.16	0.79	122.8	2.00×10^{17}	0.17	[ ]	21	[ ]	10.6	[ ]	[ ]	270
Outlet Nozzle 2	0.16	0.72	121.00	2.00×10^{17}	0.17	[ ]	21	[ ]	10.4	[ ]	[ ]	270
Outlet Nozzle 3	0.16	0.72	121.00	2.00×10^{17}	0.17	[ ]	21	[ ]	10.4	[ ]	[ ]	270
Inlet Nozzle Weld 1	[ ]	[ ]	[ ]	2.37×10^{17}	0.19	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Inlet Nozzle Weld 2	[ ]	[ ]	[ ]	2.37×10^{17}	0.19	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Inlet Nozzle Weld 3	[ ]	[ ]	[ ]	2.37×10^{17}	0.19	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Outlet Nozzle Weld	[ ]	[ ]	[ ]	2.00×10^{17}	0.17	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
US to IS Circumferential Weld	0.26	0.60	180.0	1.13×10^{19}	1.03	-33.2	186	12.2	28.0	61.1	214	300
IS to LS Circumferential Weld	0.23	0.59	167.6	9.86×10^{19}	1.51	-53.5	253	12.8	28.0	61.6	261	300

Table 4.2.2-1: RT_{PTS} Calculations for Turkey Point Unit 3 Extended Beltline Materials at 72 EFPY

Reactor Vessel Material	Cu (Wt. %)	Ni (Wt. %)	CF(1) (°F)	Fluence (n/cm^2, E>1.0 MeV)	FF(2)	$RT_{NDT(U)}$(3) (°F)	ΔRT_{NDT}(4) (°F)	σ_u(3) (°F)	σ_Δ(5) (°F)	Margin (°F)	RT_{PTS} (°F)	PTS Limit (°F)
IS to LS using Surveillance Data	0.23	0.59	151.1	9.86×10^{19}	1.51	-53.5	228	12.8	28.0	61.6	236	300
LS to Transition Ring Circumferential Weld	0.23	0.52	157.4	1.36×10^{17}	0.13	[ ]	21	[ ]	10.6	[ ]	[ ]	300

Notes for Table 4.2.2-1

1. Value calculated using Regulatory Guide 1.99, Revision 2.
2. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.
3. Initial RT_{NDT} values are for unirradiated material. Note that σ_U = 0°F for measured test values.
4. ΔRT_{NDT} = CF * FF where CF = chemistry factor.
5. Per 10 CFR 50.61, the base metal σ_Δ= 17°F for Position 1.1 and σ_Δ = 8.5°F for Position 2.1 with credible surveillance data; the weld metal σ_Δ = 28°F for Position 1.1 and σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5 *ΔRT_{NDT}.

Table 4.2.2-2
RT_{PTS} Calculations for Turkey Point Unit 4 Extended Beltline Materials at 72 EFPY

Table 4.2.2-2: RT_{PTS} Calculations for Turkey Point Unit 4 Extended Beltline Materials at 72 EFPY

Reactor Vessel Material	Cu (Wt. %)	Ni (Wt. %)	$CF^{(1)}$ (°F)	Fluence (n/cm^2, E>1.0 MeV)	$FF^{(2)}$	$RT_{NDT(U)}^{(3)}$ (°F)	$\Delta RT_{NDT}^{(4)}$ (°F)	$\sigma_u^{(3)}$ (°F)	$\sigma_\Delta^{(5)}$ (°F)	Margin (°F)	RT_{PTS} (°F)	PTS Limit (°F)
Upper Shell (US) Forging	[ ]	0.70	[ ]	1.15×10^{19}	1.04	40	[ ]	0.0	[ ]	[ ]	[ ]	270
Intermediate Shell (IS) Forging	0.054	0.69	33.4	1.08×10^{20}	1.52	50	51	0.0	17.0	34.0	135	270
Lower Shell (LS) Forging	0.056	0.74	34.6	9.81×10^{19}	1.51	40	52	0.0	17.0	34.0	126	270
LS using Surveillance Data	0.056	0.74	4.9	9.81×10^{19}	1.51	40	7	0.0	3.7	7.3	55	270
Lower Head Ring (transition)	[ ]	0.69	[ ]	1.36×10^{17}	0.13	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Inlet Nozzle 1	0.08	0.71	51.0	2.49×10^{17}	0.20	[ ]	10	[ ]	5.0	[ ]	[ ]	270
Inlet Nozzle 2	0.16	0.84	123.4	2.49×10^{17}	0.20	[ ]	24	[ ]	12.1	[ ]	[ ]	270
Inlet Nozzle 3	0.16	0.75	121.8	2.49×10^{17}	0.20	[ ]	24	[ ]	12.0	[ ]	[ ]	270
Outlet Nozzle 1	0.16	0.78	122.5	2.01×10^{17}	0.17	[ ]	21	[ ]	10.6	[ ]	[ ]	270
Outlet Nozzle 2	0.16	0.68	120.0	2.01×10^{17}	0.17	[ ]	21	[ ]	10.4	[ ]	[ ]	270
Outlet Nozzle 3	0.16	0.70	120.5	2.01×10^{17}	0.17	[ ]	21	[ ]	10.4	[ ]	[ ]	270
Inlet Nozzle Weld 1	[ ]	[ ]	[ ]	2.49×10^{17}	0.20	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Inlet Nozzle Weld 2	[ ]	[ ]	[ ]	2.49×10^{17}	0.20	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Inlet Nozzle Weld 3	[ ]	[ ]	[ ]	2.49×10^{17}	0.20	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Outlet Nozzle Weld 1	[ ]	[ ]	[ ]	2.01×10^{17}	0.17	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
Outlet Nozzle Weld 2(6)	[ ]	[ ]	[ ]	2.01×10^{17}	0.17	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	270
US to IS Circumferential Weld(7)	0.26	0.60	180.0	1.15×10^{19}	1.04	-33.2	187	12.2	28.0	61.1	215	300
IS to LS Circumferential Weld	0.23	0.59	167.6	9.81×10^{19}	1.51	-53.5	253	12.8	28.0	61.6	261	300

Table 4.2.2-2: RT_{PTS} Calculations for Turkey Point Unit 4 Extended Beltline Materials at 72 EFPY

Reactor Vessel Material	Cu (Wt. %)	Ni (Wt. %)	$CF^{(1)}$ (°F)	Fluence (n/cm^2, E>1.0 MeV)	$FF^{(2)}$	$RT_{NDT(U)}^{(3)}$ (°F)	$\Delta RT_{NDT}^{(4)}$ (°F)	$\sigma_u^{(3)}$ (°F)	$\sigma_\Delta^{(5)}$ (°F)	Margin (°F)	RT_{PTS} (°F)	PTS Limit (°F)
IS to LS using Surveillance Data	0.23	0.59	151.1	9.81×10^{19}	1.51	-53.5	228	12.8	28.0	61.6	236	300
LS to Transition Ring Circumferential Weld	0.23	0.52	157.4	1.36×10^{17}	0.13	[ ]	21	[ ]	10.6	[ ]	[ ]	300

Notes for Table 4.2.2-2

1. Value calculated using Regulatory Guide 1.99, Revision 2.
2. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.
3. Initial RT_{NDT} values are for unirradiated material. Note that σ_U = 0°F for measured test values.
4. ΔRT_{NDT} = CF * FF where CF = chemistry factor.
5. Per 10 CFR 50.61, the base metal σ_Δ = 17°F for Position 1.1 and σ_Δ = 8.5°F for Position 2.1 with credible surveillance data; the weld metal σ_Δ = 28°F for Position 1.1 and σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5 *ΔRT_{NDT}.
6. Unit 4 has an additional outlet weld because of use of different material.
7. Inside 67%. Outside 33% N/A for PTS.

4.2.3 Upper-Shelf Energy

TLAA Description

The current licensing basis Upper Shelf Energy (USE) calculations were prepared for PTN reactor vessel beltline materials for 48 EFPY. Since the USE value is a function of 48 EFPY fluence which is associated with the 60-year licensed operating period, these USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation

Appendix G of 10 CFR Part 50, Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy USE of no less than 75 ft-lb initially, and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

Per Regulatory Guide 1.99, Revision 2 (Reference 4.2.6.4), the Charpy USE should be assumed to decrease as a function of fluence according to Figure 2 of the Regulatory Guide when credible surveillance data is not available. If credible surveillance data is available, the decrease in USE may be obtained by plotting the reduced plant surveillance data on Figure 2 of the Regulatory Guide and fitting the data with a line drawn parallel to the existing lines as the upper bound of all of the data.

The PTN reactor vessels were fabricated by Babcock & Wilcox (B&W) and consist of the upper shell forgings, intermediate shell forgings, lower shell forgings, upper shell forging-to-intermediate shell forging circumferential weld seams, intermediate shell forging-to-lower shell forging circumferential weld seams and lower shell forging-to-transition ring circumferential weld seams. No longitudinal welds are used on the PTN reactor vessels. The inlet and outlet nozzles are also fabricated from forged material.

USE was evaluated for all materials included in the original and extended beltline. Fracture toughness criteria in 10 CFR Part 50 Appendix G requires that beltline materials maintain USE no less than 50 ft-lb during operation of the reactor unless a lower USE can be demonstrated to be acceptable as described below. 10 CFR Part 50, Appendix G requires licensees to submit an analysis at least 3 years prior to the time that the USE of any of the reactor vessel material is predicted to drop below 50 ft-lb., as measured by Charpy V-notch specimen testing. The PTN limiting circumferential weld material Charpy USE dropped below fifty foot pounds early in plant life. At that time, a fracture mechanics evaluation was performed to demonstrate acceptable equivalent margins of safety against fracture. The NRC reviewed these evaluations, as documented in October 19, 1993 (Reference 4.2.6.6), and May 9, 1994 (Reference 4.2.6.7), letters to FPL. These references approved plant operation through the initial license term (32 EFPY). As part of the original license renewal effort, an additional fracture mechanics evaluation was performed in accordance with Appendix K of ASME Section XI to demonstrate continued acceptable equivalent margins of safety against fracture through 48 EFPY (Reference 4.2.6.8). This evaluation concluded that the limiting weld for the PTN reactor vessels satisfies the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Appendix K, for ductile flaw extension and tensile instability. The NRC reviewed and accepted this evaluation, as documented in NUREG-1759 (Reference 4.2.6.9).

Extended power uprate (EPU) license amendment requests were submitted by FPL letters dated October 21 (Reference 4.2.6.10) and December 14, 2010 (Reference 4.2.6.11) to increase the licensed core power level for Turkey Point Units 3 and 4 from 2300 megawatts thermal (MWt) to 2644 MWt. The EPU license amendments were approved by the NRC as documented in the safety evaluation related to the amendments (Reference 4.2.6.12). As part of the EPU analyses, an additional USE fracture mechanics evaluation was performed in accordance with Appendix K of ASME Section XI to demonstrate continued acceptable equivalent margins of safety against fracture through 48 EFPY using the EPU fluence values. The fluence values at a postulated flaw depth at a location one quarter of the vessel wall thickness from the clad/base metal interface (¼T) were used and the USE projection was performed in accordance with RG 1.99, Revision 2. The projection demonstrated that the USE of all the beltline materials remains above 50 foot-pounds ft-lb) at 60 years, with the exception of the lower shell (LS) to intermediate shell (IS) circumferential welds and IS to upper shell (US) welds for both units. For the reactor vessel materials where USE is projected to fall below 50 foot-pounds, a revision to the equivalent margins analysis (EMA) was performed accounting for EPU and 48 EFPY. This evaluation concluded that the limiting weld for the PTN reactor vessels satisfies the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Appendix K, for ductile flaw extension and tensile instability.

The NRC reviewed and accepted the USE and EMA evaluations, as documented in the safety evaluation related to the EPU license amendments (Reference 4.2.6.12).

For subsequent license renewal, the USE values for the beltline and extended beltline materials were determined using methods consistent with Regulatory Guide 1.99 (Reference 4.2.6.4).

Two methods can be used to predict the decrease in USE with irradiation, depending on the availability of credible surveillance capsule data as defined in Regulatory Guide 1.99. For vessel beltline materials that are not in the surveillance program or for locations with non-credible data, the Charpy USE is assumed to decrease as a function of fluence and copper content, as indicated in Regulatory Guide 1.99, Revision 2 (Position 1.2). When two or more credible surveillance data sets are available from the reactor, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with the regulatory guide to predict the change in USE of the reactor vessel material due to irradiation (Position 2.2).

The 72 EFPY Regulatory Guide 1.99, Revision 2 (Position 1.2) USE values of the vessel materials can be predicted using the corresponding ¼T fluence projection, the copper content of the materials, and Figure 2 in Regulatory Guide 1.99, Revision 2. The predicted Position 2.2 USE values are determined for the reactor vessel materials that are contained in the surveillance program by using the plant surveillance data along with the corresponding ¼T fluence projection.

The projected USE values were calculated to determine if the Turkey Point Units 3 and 4 beltline and extended beltline materials remain above the 50 ft-lb limit at 72 EFPY. The results are summarized in Tables 4.2.3-1 and 4.2.3-2.

All Turkey Point Unit 3 reactor vessel materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for the IS to LS and US to IS circumferential welds.

All Turkey Point Unit 4 reactor vessel materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for the IS to LS and US to IS circumferential welds, and the inlet and outlet nozzle welds.

For the Turkey Point Units 3 and 4 reactor vessel materials that do not maintain a USE value above 50 ft-lbs through 72 EFPY, an EMA was performed. The EMA analysis is further discussed below.

Equivalent Margins Analysis (EMA)

The ASME Section XI, acceptance criteria for Levels A through D Service Loadings for all Turkey Point 3 and 4 reactor vessel beltline and extended beltline Linde 80 welds are satisfied and are reported in AREVA reports (Reference 4.2.6.15 and Reference 4.2.6.16). The results of the EMA for Turkey Point Units 3 and 4 are summarized below.

Levels A & B Service Loadings

Reactor Vessel Shell Welds

- The limiting RV shell weld is circumferential weld (SA-1101). With factors of safety of 1.15 on pressure and 1.0 on thermal loading, the applied *J*-integral (*J*1) is less than the *J*-integral of the material at a ductile flaw extension of 0.10 in. (*J*0.1). The ratio *J*0.1/*J*1 is greater than the required value of 1.0.

- With a factor of safety of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied *J*-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

Reactor Vessel Transition Welds and RV Nozzle Welds

- The limiting weld considering RV transition welds (upper and lower) and the RV inlet and outlet nozzle-to-shell welds is the RV inlet nozzle-to-shell weld. With factors of safety of 1.15 on pressure and 1.0 on thermal loading, the applied *J*-integral (*J*1) is less than the *J*-integral of the material at a ductile flaw extension of 0.10 in. (*J*0.1). The ratio *J*0.1/*J*1 is greater than the required value of 1.0.

- With a factor of safety of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied *J*-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

Levels C & D Service Loadings

The limiting reactor vessel shell weld (SA-1101), limiting upper transition weld, and RV inlet and outlet nozzle-to-shell welds were evaluated for Levels C and D Service Loadings.

Reactor Vessel Shell Welds, Upper Transition Weld, and RV Nozzle Welds

- With a factor of safety of 1.0 on loading, the applied *J*-integral (J_1) for the limiting reactor vessel shell weld (SA-1101) is less than the lower bound *J*-integral of the material at a ductile flaw extension of 0.10 inch ($J_{0.1}$) with a ratio $J_{0.1}/J_1$ is greater than the required value of 1.0.

- With a factor of safety of 1.0 on loading, the applied *J*-integral (J_1) for the RV nozzle-to-shell welds and upper transition weld are less than the lower bound *J*-integral of the material at a ductile flaw extension of 0.10 inch ($J_{0.1}$).

- With a factor of safety of 1.0 on loading, flaw extensions are ductile and stable for the limiting reactor vessel shell weld (SA-1101) since the slope of the applied *J*-integral curve is less than the slopes of both the lower bound and mean J-R curves at the points of intersection. This requirement is also satisfied for the RV outlet nozzle-to-shell weld (i.e., limiting location considering RV nozzle-to-shell welds and upper transition weld).

- For weld SA-1101 and the RV outlet nozzle-to-shell weld flaw growth is stable at much less than 75% of the vessel wall thickness. Also, the remaining ligament is sufficient to preclude tensile instability by a large margin.

B&WOG J-R Model

The original B&WOG J-R Model 4B reported in BAW-2192PA, Appendix A (Reference 4.2.6.14) was used to obtain J material (i.e. J(0.1)) for the 80-year equivalent margins analyses reported in Reference 4.2.6.15 and Reference 4.2.6.16. Model 4B is based on fracture toughness data irradiated to a fluence ranging from 0.0 to 8.45 x 10^{18} n/cm^2, which is less than the peak ¼T 80-year fluence projected for PTN at 6.5 x 10^{19} n/cm^2. To further substantiate the use of the B&WOG J-R model, the original J delta-a data used to generate the B&WOG J-R model 4B was used to independently benchmark the original B&WOG model using the R-project statistical tool. The benchmark is designated B&WOG J-R Model 5B. New J-R data with fluence to 5.8 x 10^{19} n/cm^2 was then added to the original population of welds and the fitting coefficients (assuming the same model form) were generated. The B&WOG model that includes the total population of J delta-a data is designated Model 6B. Model 6B is based on test data out to a fluence of 5.8 x 10^{19} n/cm^2, which is slightly less than the peak ¼T fluence for PTN limiting weld SA-1101.

Use of Model 6B for fluence values in excess of 5.8 x 10^{19} n/cm^2 is considered to be a model extrapolation and the uncertainty may increase (i.e., -2SE). However, based on recent fracture toughness test data at 2.9 x 10^{19} n/cm^2 and 5.8 x 10^{19} n/cm^2, the Linde 80 J-R test data and model approaches saturation, and model uncertainty is not expected to increase for the highest fluence values expected at 80 years (i.e., for PTN weld SA-1101 6.5 x 10^{19} n/cm^2 at ¼ T and 8.63 x 10^{19} n/cm^2 at T/10). For PTN, use of Model 6B (model extrapolation) slightly reduced the J(0.1)/J1 margins when compared to Model 4B; however, all margins remain significantly above the acceptance criterion of 1.0. In addition, the combination of Level C and D acceptance criteria applied to Level D transients provides additional conservatism in the equivalent margins analyses. The B&WOG J-R model (including Models 4B, 5B, and 6B) is discussed in Reference 4.2.6.15.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The USE analyses have been projected to the end of the SPEO.

Table 4.2.3-1
Turkey Point Unit 3 Predicted Position 1.2 USE Values at 72 EFPY

Reactor Vessel Material	Cu (Wt. %)	¼T EOL Fluence(1) (n/cm^2, E>1.0 MeV)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)(2)(3)	Projected EOL USE(ft-lb)
Upper Shell (US) Forging	[ ]	6.59 x 10^{18}	99	[ ]	[ ]
Intermediate Shell (IS) Forging	0.058	6.78 x 10^{19}	93	30	65
Lower Shell (LS) Forging	0.079	6.19 x 10^{19}	100	30	70
Lower Head Ring (transition)	[ ]	1.02 x 10^{17}	97	[ ]	[ ]
US to IS Circumferential Weld	0.26	7.10 x 10^{18}	[ ]	36	[ ](4)
IS to LS Circumferential Weld	0.23	6.19 x 10^{19}	[ ]	60	[ ](4)
LS to Transition Ring Circumferential Weld	0.23	1.02 x 10^{17}	[ ]	22	[ ]
Inlet Nozzle 1	0.16	1.27 x 10^{17}	109	15	93
Inlet Nozzle 2	0.16	1.27 x 10^{17}	109	15	93
Inlet Nozzle 3	0.16	1.27 x 10^{17}	109	15	93
Outlet Nozzle 1	0.16	1.05 x 10^{17}	109	15	93
Outlet Nozzle 2	0.16	1.05 x 10^{17}	109	15	93
Outlet Nozzle 3	0.16	1.05 x 10^{17}	109	15	93
Inlet Nozzle Weld 1	[ ]	1.27 x 10^{17}	[ ]	[ ]	[ ]
Inlet Nozzle Weld 2	[ ]	1.27 x 10^{17}	[ ]	[ ]	[ ]
Inlet Nozzle Weld 3	[ ]	1.27 x 10^{17}	[ ]	[ ]	[ ]
Outlet Nozzle Weld	[ ]	1.05 x 10^{17}	[ ]	[ ]	[ ]

Notes for Table 4.2.3-1

1. The ¼T fluence was calculated using the Regulatory Guide 1.99, Revision 2, Position 1.2, and the Turkey Point Unit 3 reactor vessel beltline wall thickness of 7.75 inches.
2. The minimum fluence value on Figure 2 of Regulatory Guide 1.99, Revision 2 is 1 x 10^{18} n/cm^2 (E > 1.0 MeV) and the maximum value is 6 x 10^{19} n/cm^2 (E > 1.0 MeV). For projections with fluence less that 1 x 10^{18} n/cm^2 the decrease at 1 x 10^{18} n/cm^2 will be used. For projections with the fluence greater than 6 x 10^{19} n/cm^2 the decrease will be estimated at the lesser of the next higher copper value line or the maximum predicted decrease of 60%
3. USE decrease values were calculated in accordance with Regulatory Guide 1.99, Revision 2, Position 1.2. The percent USE decrease values that corresponded to each material's specific Cu (wt. %) value were determined using interpolation between the existing weld or base metal lines.
4. For locations where the projected EOL USE values that fall below 50 ft-lbs, an EMA was performed demonstrating acceptability.

Table 4.2.3-2
Turkey Point Unit 4 Predicted Position 1.2 USE Values at 72 EFPY

Reactor Vessel Material	Cu (Wt. %)	¼T EOL Fluence(1) (n/cm^2, E>1.0 MeV)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)(2)(3)	Projected EOL USE(ft-lb)
Upper Shell (US) Forging	[ ]	6.70×10^{18}	103	[ ]	[ ]
Intermediate Shell (IS) Forging	0.054	6.78×10^{19}	88	30	62
Lower Shell (LS) Forging	0.056	6.16×10^{19}	97	30	68
Lower Head Ring (transition)	[ ]	1.02×10^{17}	109	[ ]	[ ]
US to IS Circumferential Weld (Inner 67%)	0.26	7.22×10^{18}	[ ]	36	[ ](4)
US to IS Circumferential Weld (Outer 33%)	0.32	2.85×10^{18}	[ ]	36	[ ](4)(5)
IS to LS Circumferential Weld	0.23	6.16×10^{19}	[ ]	60	[ ](4)
LS to Transition Ring Circumferential Weld	0.23	1.02×10^{17}	[ ]	22	[ ]
Inlet Nozzle 1	0.08	1.45×10^{17}	109	11	97
Inlet Nozzle 2	0.16	1.45×10^{17}	109	15	93
Inlet Nozzle 3	0.16	1.45×10^{17}	105	15	89
Outlet Nozzle 1	0.16	1.17×10^{17}	107	15	91
Outlet Nozzle 2	0.16	1.17×10^{17}	104	15	88
Outlet Nozzle 3	0.16	1.17×10^{17}	93	15	79
Inlet Nozzle Weld 1	[ ]	1.45×10^{17}	[ ]	[ ]	[ ]
Inlet Nozzle Weld 2	[ ]	1.45×10^{17}	[ ]	[ ]	[ ]
Inlet Nozzle Weld 3	[ ]	1.45×10^{17}	[ ]	[ ]	[ ](4)
Outlet Nozzle Weld 1	[ ]	1.17×10^{17}	[ ]	[ ]	[ ]
Outlet Nozzle Weld 2(6)	[ ]	1.17×10^{17}	[ ]	[ ]	[ ](4)

Notes for Table 4.2.3-2

1. The ¼T fluence was calculated using the Regulatory Guide 1.99, Revision 2, Position 1.2, and the Turkey Point Unit 4 reactor vessel beltline wall thickness of 7.75 inches.
2. The minimum fluence value on Figure 2 of Regulatory Guide 1.99, Revision 2 is 1×10^{18} n/cm^2 (E > 1.0 MeV) and the maximum value is 6×10^{19} n/cm^2 (E > 1.0 MeV). For projections with fluence less that 1×10^{18} n/cm^2 the decrease at 1×10^{18} n/cm^2 will be used. For projections with the fluence greater than 6×10^{19} n/cm^2 the decrease will be estimated at the lesser of the next higher copper value line or the maximum predicted decrease of 60%.
3. USE decrease values were calculated in accordance with Regulatory Guide 1.99, Revision 2, Position 1.2. The percent USE decrease values that corresponded to each material's specific Cu (wt. %) value were determined using interpolation between the existing weld or base metal lines.
4. For locations where the projected EOL USE values that fall below 50 ft-lbs, an EMA was performed demonstrating acceptability.
5. This portion of the US to IS weld uses ¾T fluence since this material is at the outside 33% thickness.
6. Unit 4 has an additional outlet weld because of use of different material.

4.2.4 Adjusted Reference Temperature

TLAA Description

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. Regulatory Guide 1.99, Revision 2, provides the methodology for determining the ART of the limiting material. The initial nil ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. 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 Part 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) means that higher temperatures are required for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + (ΔRT_{NDT}) + Margin. Since the ΔRT_{NDT} value is a function of 48 EFPY fluence which is associated with the 60-year licensed operating period, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation

As described in Section 4.2.1, 72 EFPY fluence values were determined for Turkey Point Units 3 and 4 for the RPV beltline and extended beltline components. These 72 EFPY ¼T fluence values were used to compute the ART values of Turkey Point Units 3 and 4, in accordance with Regulatory Guide 1.99, Revision 2 (Reference 4.2.6.4). Tables 4.2.4-1 and 4.2.4-2 present the ART results for Turkey Point Units 3 and 4, respectively. Note as is typically done for PTN ART submittals, ¾ T ART values are provided for information.

The ART values of the limiting beltline materials at 72 EFPY for each unit are listed below:

- The limiting 72 EFPY ART values for Turkey Point Unit 3 correspond to the intermediate to lower shell circumferential weld.

- The limiting 72 EFPY ART values for Turkey Point Unit 4 correspond to the intermediate to lower shell circumferential weld.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The ART analyses have been projected to the end of the SPEO. They may be used as inputs to 72 EFPY P-T limits for the SPEO.

Table 4.2.4-1
Turkey Point Unit 3 ART Calculations for 72 EFPY

Table 4.2.4-1: Turkey Point Unit 3 ART Calculations for 72 EFPY

Reactor Vessel Material	Reg. Guide 1.99 Rev. 2 Position	CF (°F)	$RT_{NDT(U)}$ (°F)	σ_u (°F)	σ_Δ[1] (°F)	Margin (°F)	¼T Fluence (n/cm^2, E>1.0 MeV)	¼T FF	¼T ΔRT_{NDT} (°F)	¼T ART (°F)	¾T Fluence (n/cm^2, E>1.0 MeV)	¾T FF	¾T ΔRT_{NDT} (°F)	¾T ART (°F)
Upper Shell (US) Forging	1.1	[ ]	50	0.0	[ ]	[ ]	6.59×10^{18}	0.88	[ ]	[ ]	2.24×10^{18}	0.60	[ ]	[ ]
Intermediate Shell (IS) Forging	1.1	37.0	40	0.0	17.0	34.0	6.78×10^{19}	1.46	53.9	128	2.68×10^{19}	1.26	47	121
IS using Surveillance Data	2.1	6.9	40	0.0	5.0	10.0	6.78×10^{19}	1.46	10.0	60	2.68×10^{19}	1.26	9	59
Lower Shell (LS) Forging	1.1	51.0	30	0.0	17.0	34.0	6.19×10^{19}	1.44	73.6	138	2.44×10^{19}	1.24	63	127
LS using Surveillance Data	2.1	48.7	30	0.0	17.0	34.0	6.19×10^{19}	1.44	70.2	134	2.44×10^{19}	1.24	60	124
Lower Head Ring (transition)	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.04×10^{17}	0.11	[ ]	[ ]	N/A[2]	N/A	N/A	N/A
Inlet Nozzle 1	1.1	122.0	[ ]	[ ]	8.3	[ ]	1.38×10^{17}	0.14	16.6	[ ]	N/A[2]	N/A	N/A	N/A
Inlet Nozzle 2	1.1	121.5	[ ]	[ ]	8.3	[ ]	1.38×10^{17}	0.14	16.5	[ ]	N/A[2]	N/A	N/A	N/A
Inlet Nozzle 3	1.1	123.0	[ ]	[ ]	8.4	[ ]	1.38×10^{17}	0.14	16.7	[ ]	N/A[2]	N/A	N/A	N/A
Outlet Nozzle 1	1.1	122.8	[ ]	[ ]	7.5	[ ]	1.17×10^{17}	0.12	14.9	[ ]	N/A[2]	N/A	N/A	N/A
Outlet Nozzle 2	1.1	121.0	[ ]	[ ]	7.4	[ ]	1.17×10^{17}	0.12	14.7	[ ]	N/A[2]	N/A	N/A	N/A
Outlet Nozzle 3	1.1	121.0	[ ]	[ ]	7.4	[ ]	1.17×10^{17}	0.12	14.7	[ ]	N/A[2]	N/A	N/A	N/A
Inlet Nozzle Weld	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.38×10^{17}	0.14	[ ]	[ ]	N/A[2]	N/A	N/A	N/A
Inlet Nozzle Weld	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.38×10^{17}	0.14	[ ]	[ ]	N/A[2]	N/A	N/A	N/A
Inlet Nozzle Weld	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.38×10^{17}	0.14	[ ]	[ ]	N/A[2]	N/A	N/A	N/A
Outlet Nozzle Weld	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.17×10^{17}	0.12	[ ]	[ ]	N/A[2]	N/A	N/A	N/A
US to IS Circumferential Weld	1.1	180.0	-33.2	12.2	28.0	61.1	7.10×10^{18}	0.90	162.7	191	2.80×10^{18}	0.65	117	145

Table 4.2.4-1: Turkey Point Unit 3 ART Calculations for 72 EFPY

Reactor Vessel Material	Reg. Guide 1.99 Rev. 2 Position	CF (°F)	$RT_{NDT(U)}$ (°F)	σ_u (°F)	σ_Δ (1) (°F)	Margin (°F)	¼T Fluence (n/cm^2, E>1.0 MeV)	¼T FF	¼T ΔRT_{NDT} (°F)	¼T ART (°F)	¾T Fluence (n/cm^2, E>1.0 MeV)	¾T FF	¾T ΔRT_{NDT} (°F)	¾T ART (°F)
IS to LS Circumferential Weld	1.1	167.6	-53.5	12.8	28.0	61.6	6.19×10^{19}	1.44	241.7	250	2.44×10^{19}	1.24	208	216
IS to LS using Surveillance Data	2.1	151.1	-53.5	12.8	28.0	61.6	6.19×10^{19}	1.44	217.5	226	2.44×10^{19}	1.24	187	195
LS to Transition Ring Circumferential Weld	1.1	157.4	[ ]	[ ]	8.8	[ ]	1.02×10^{17}	0.11	17.5	[ ]	N/A (2)	N/A	N/A	N/A

Notes for Table 4.2.4-1

1. For ¾T ΔRT_{NDT} that is less than σ_Δ, the ¾T used the same value as the σ_Δ for ¼T for simplicity since the ΔRT_{NDT} for these materials were not limiting.
2. For the inlet and outlet nozzles and welds, and the lower transition ring and weld, only the ¼T attenuated fluences were calculated and considered equal at the ¾T locations.

Table 4.2.4-2
Turkey Point Unit 4 ART Calculations for 72 EFPY

Reactor Vessel Material	Reg. Guide 1.99 Rev. 2 Position	CF (°F)	$RT_{NDT(U)}$ (°F)	σ_u (°F)	σ_Δ(1) (°F)	Margin (°F)	¼T Fluence (n/cm^2, E>1.0 MeV)	¼T FF	¼T ΔRT_{NDT} (°F)	¼T ART (°F)	¾T Fluence (n/cm^2, E>1.0 MeV)	¾T FF	¾T ΔRT_{NDT} (°F)	¾T ART (°F)
Upper Shell (US) Forging	1.1	[ ]	40	0.0	[ ]	[ ]	6.70×10^{18}	0.89	[ ]	[ ]	2.28×10^{18}	0.60	[ ]	[ ]
Intermediate Shell (IS) Forging	1.1	33.4	50	0.0	17.0	34.0	6.78×10^{19}	1.46	48.7	133	2.68×10^{19}	1.26	42	126
Lower Shell (LS) Forging	1.1	34.6	40	0.0	17.0	34.0	6.16×10^{19}	1.44	49.9	124	2.43×10^{19}	1.24	43	117
LS using Surveillance Data	2.1	4.9	40	0.0	3.5	7.0	6.16×10^{19}	1.44	7.0	54	2.43×10^{19}	1.24	6	53
Lower Head Ring (transition)	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.02×10^{17}	0.11	[ ]	[ ]	N/A(2)	N/A	N/A	N/A
Inlet Nozzle 1	1.1	51.0	[ ]	[ ]	3.6	[ ]	1.45×10^{17}	0.14	7.2	[ ]	N/A(2)	N/A	N/A	N/A
Inlet Nozzle 2	1.1	123.4	[ ]	[ ]	8.7	[ ]	1.45×10^{17}	0.14	17.3	[ ]	N/A(2)	N/A	N/A	N/A
Inlet Nozzle 3	1.1	121.8	[ ]	[ ]	8.5	[ ]	1.45×10^{17}	0.14	17.1	[ ]	N/A(2)	N/A	N/A	N/A
Outlet Nozzle 1	1.1	122.5	[ ]	[ ]	7.5	[ ]	1.17×10^{17}	0.12	14.9	[ ]	N/A(2)	N/A	N/A	N/A
Outlet Nozzle 2	1.1	120.0	[ ]	[ ]	7.3	[ ]	1.17×10^{17}	0.12	14.6	[ ]	N/A(2)	N/A	N/A	N/A
Outlet Nozzle 3	1.1	120.5	[ ]	[ ]	7.3	[ ]	1.17×10^{17}	0.12	14.7	[ ]	N/A(2)	N/A	N/A	N/A
Inlet Nozzle Weld 1	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.45×10^{17}	0.14	[ ]	[ ]	N/A(2)	N/A	N/A	N/A
Inlet Nozzle Weld 2	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.45×10^{17}	0.14	[ ]	[ ]	N/A(2)	N/A	N/A	N/A
Inlet Nozzle Weld 3	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.45×10^{17}	0.14	[ ]	[ ]	N/A(2)	N/A	N/A	N/A
Outlet Nozzle Weld 1	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.17×10^{17}	0.12	[ ]	[ ]	N/A(2)	N/A	N/A	N/A
Outlet Nozzle Weld 2	1.1	[ ]	[ ]	[ ]	[ ]	[ ]	1.17×10^{17}	0.12	[ ]	[ ]	N/A(2)	N/A	N/A	N/A
US to IS Circumferential Weld Inside 67%(3)	1.1	180.0	-33.2	12.2	28.0	61.1	7.22×10^{18}	0.91	163.6	191	N/A	N/A	N/A	N/A
US to IS Circumferential Weld Outside 33%(4)	1.1	199.3	-31.1	13.7	28.0	62.3	N/A	N/A	N/A	N/A	2.85×10^{18}	0.66	131	162
IS to LS Circumferential Weld	1.1	167.55	-53.5	12.8	28.0	61.6	6.16×10^{19}	1.44	241.5	250	2.43×10^{19}	1.24	208	216
IS to LS using Surveillance Data	2.1	151.1	-53.5	12.8	28.0	61.6	6.16×10^{19}	1.44	217.7	226	2.43×10^{19}	1.24	187	195
LS to Transition Ring Circumferential Weld	1.1	157.4	[ ]	[ ]	8.8	[ ]	1.02×10^{17}	0.11	17.5	[ ]	N/A(2)	N/A	N/A	N/A

Notes for Table 4.2.4-2

1. For ¾T ΔRT_{NDT} that is less than σ_{Δ}, the ¾T used the same value as the σ_{Δ} for ¼T for simplicity since the ΔRT_{NDT} for these materials were not limiting.
2. For the inlet and outlet nozzles and welds, and the lower transition ring and weld, only the ¼T attenuated fluences were calculated and considered equal at the ¾T locations.
3. Only ¼T applicable.
4. Only ¾T applicable.

4.2.5 Pressure-Temperature Limits and LTOP Setpoints

TLAA Description

10 CFR Part 50 Appendix G requires that the reactor vessel be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor vessel is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated reactor vessel fluence effect on fracture toughness.

The current P-T limits are based upon fluence projections that were considered to represent the amount of power to be generated over 60 years of plant operation, assuming a 60-year average capacity factor of 80 percent. Since they are currently based upon a 60-year assumption regarding capacity factor, the P-T limits satisfy the criteria of 10 CFR 54.3(a) and have been identified as TLAAs.

TLAA Evaluation

In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the SPEO need not be submitted as part of the SLRA since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits that are located in the Technical Specifications. The 10 CFR 50.90 process will ensure that the P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current period of operation.

The current Turkey Point Units 3 and 4 heatup and cooldown curves were calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the reactor vessel for 48 EFPY based on EPU fluences. The Turkey Point Units 3 and 4 reactor vessel P-T limit curves are contained in plant Technical Specifications 3/4.4.9. Prior to exceeding 48 EFPY, new P-T limit curves will be generated to cover plant operation beyond 48 EFPY. The P-T limit curves will be developed using NRC-approved analytical methods. The analysis of the P-T curves will consider locations outside of the beltline such as nozzles, penetrations and other discontinuities to determine if more restrictive P-T limits are required than would be determined by considering only the reactor vessel beltline materials.

Additionally, PTN Technical Specifications 3/4.4.9.3 specify the power operated relief valve (PORV) lift settings to mitigate the consequences of low temperature overpressure (LTOP) events. Each time the P-T limit curves are revised, the LTOP PORV setpoints must be reevaluated. Therefore, LTOP protection limits are considered part of the calculation of P-T curves.

The P-T limit curves and LTOP PORV setpoints will be updated (if required) and a Technical Specification change request will be submitted for approval prior to exceeding the current 48 EFPY limits.

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 for the SPEO. The Reactor Vessel Material Surveillance AMP (Section B.2.3.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the current terms of applicability in the Technical Specifications for Turkey Point Units 3 and 4.

4.2.6 References

4.2.6.1 Regulatory Guide 1.190, "Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U.S. Nuclear Regulatory Commission, March 2001.

4.2.6.2 Westinghouse Electric Company Document WCAP-14040-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” May 2004.

4.2.6.3 Westinghouse Electric Company Document WCAP-16083-NP-A, Revision 0, “Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry,” May 2006.

4.2.6.4 Regulatory Guide 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” U.S. Nuclear Regulatory Commission, May 1988.

4.2.6.5 J. Page (NRC) letter to M. Nazar (FPL), “Turkey Point Units 3 and 4 - Exemption from the Requirements of 10 CFR Part 50, Appendix G and 10 CFR Part 50, Section 50.61,” March 11, 2010 (ML072250093).

4.2.6.6 L. Raghavan (NRC) letter to J. H. Goldberg (FPL), "Turkey Point Units 3 and 4 - Review of Babcock and Wilcox Owners Group Materials Committee Reports - Upper-Shelf Energy," October 19, 1993.

4.2.6.7 Richard P. Croteau (NRC) letter to J. H. Goldberg (FPL), "Turkey Point Units 3 and 4 - Generic Letter (GL) 92-01, Revision 1, Reactor Vessel Structural Integrity," May 9, 1994.

4.2.6.8 BAW-2312, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of Turkey Point Units 3 and 4 for Extended Life through 48 Effective Full Power Years, Revision 1," Babcock and Wilcox, December 2000.

4.2.6.9 NUREG-1759, Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4, April 30, 2002.

4.2.6.10 FPL Letter No. L-2010-113 from Michael Kiley to U.S. Nuclear Regulatory Commission, “Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, License Amendment Request for Extended Power Uprate (LAR 205),” October 21, 2010, (ML103560169).

4.2.6.11 FPL Letter No. L-2010-299 from Michael Kiley to U.S. Nuclear Regulatory Commission, “Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, License Amendment Request for Extended Power Uprate (LAR 205),” December 14, 2010, (ML103560168).

4.2.6.12 Jason C. Paige (NRC) letter to Mano Nazar (FPL), "Turkey Point Units 3 and 4 - Issuance of Amendments Regarding Extended Power Uprate," June 15, 2012 (ML11293A365).

4.2.6.13 LTR-REA-17-116-NP, Revision 0, Reactor Vessel Neutron Exposure Data in Support of the Turkey Point Unit 3 and Unit 4 Subsequent License Renewal (SLR) Time-Limited Aging Analysis (TLAA), December 1, 2017 (Enclosure 4, Attachment 1).

4.2.6.14 BAW-2192PA, “Low Upper-Shelf Toughness Fracture Mechanics Analyses of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level A & B Service Loads”, April 1994

4.2.6.15 AREVA Report No. ANP-3646NP/P-000, Revision 0, Low Upper-Shelf Toughness Fracture Mechanics Analysis of Turkey Point Units 3 and 4 Reactor Vessels for Levels A & B Service Loads at 80 Years, January 5, 2018 (NP - Enclosure 4, Attachment 2, P - Enclosure 5, Attachment 2).

4.2.6.16 AREVA Report No. ANP-3647NP/P-000, Revision 0, Low Upper-Shelf Toughness Fracture Mechanics Analysis of Turkey Point Units 3 and 4 Reactor Vessels for Levels C & D Service Loads at 80 Years, January 5, 2018 (NP - Enclosure 4, Attachment 3, P - Enclosure 5, Attachment 3).

4.3 METAL FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as time-limited aging analyses for PTN. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the PTN UFSAR.

Fatigue analyses are considered TLAAs for Class 1 and non-Class 1 mechanical components. Fatigue is an age-related degradation mechanism caused by cyclic stressing of a component by either mechanical or thermal stresses.

The aging management reviews in Section 3 identify mechanical components that are within the scope of license renewal and are subject to aging management review. When TLAA – Metal Fatigue is identified in the aging management program column of the tables in Section 3, the associated fatigue analyses are evaluated in this section. Evaluation of the TLAA per 10 CFR 54.21(c)(1) determines whether

(i) the analyses remain valid for the SPEO,

(ii) the analyses have been projected to the end of the SPEO, or

(iii) the effects of aging on the intended function(s) will be adequately managed for the SPEO.

Documentation of the evaluation of Class 1 component fatigue analyses is provided in Section 4.3.1. Fatigue analysis of piping components is discussed in Section 4.3.2. Evaluation of environmentally assisted fatigue (EAF) is documented in Section 4.3.3. In addition, reactor vessel underclad cracking and RCP flywheel evaluations are documented in Sections 4.3.4 and 4.3.5, respectively.

4.3.1 Metal Fatigue of Class 1 Components

TLAA Description

The reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 1. The ASME Boiler and Pressure Vessel Code, Section III, Class 1 requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. Note that metal fatigue of piping and piping components (valves, fittings, etc.) associated with the reactor coolant, engineered safety feature, auxiliary, and main steam and power conversion systems in the scope of SLR is addressed in Section 4.3.2.

Fatigue analyses were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature, pressure, and seismic loading cycles. These ASME Section III, Class 1 fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients described in the design specifications. The intent of the design basis transient cycle definitions is to bound a wide range of possible events with varying ranges of severity in temperature, pressure, and flow. The fatigue analyses were required to demonstrate that the cumulative usage factor (CUF) will not exceed the design allowable limit of 1.0 when the equipment is exposed to all of the postulated transients. Considering the calculation of fatigue usage factors is part of the current licensing basis and is used to support safety determinations, and the number of occurrences of each transient type was based upon 60-year assumptions, these Class 1 fatigue analyses have been identified as TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

The reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 1, as described below.

Reactor Vessels

As shown in UFSAR Table 4.1-9, design and fabrication of the reactor vessels is in accordance with ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Class A, 1965 Edition through Summer 1966 Addenda. The reactor vessel closure heads (RVCH), including the control rod drive mechanism (CRDM) pressure housings, for Units 3 and 4 have been replaced. The replacement RVCH design Code is ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Subsection NB, Class 1, 1989 Edition, no Addenda. In addition, the spare CRDM housing adapters are closed with a CRDM plug. The CRDM plug design code is ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, Class 1, 1989 Edition, no addenda. The design code for the bottom-mounted instrumentation (BMI) tubing is the ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, 1989 edition, no addenda. The design code for the BMI supports is the ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, 1998 edition, no addenda.

Reactor Vessel Internals

The reactor vessel internals and core support were designed prior to the creation of the ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, using internal Westinghouse design criteria that effectively evolved to become the original NG criteria. The ASME Boiler and Pressure Vessel Code, Section III, Class 1 requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. As described in UFSAR Section 5A-1.3.2.2.2, Reactor Vessel Internals Design Analysis, loading applied to the analytical model includes: (a) deadweight of the components and contents; (b) pressure differentials due to coolant flow; (c) seismic excitation; (d) loss of coolant accident loads; (e) vibrational loading; (f) thermal expansion; and (g) preloads on certain components.

Pressurizers

The pressurizers are vertical, cylindrical vessels with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to reactor coolant. As shown in UFSAR Table 4.1-9, design and fabrication of the pressurizers is in accordance with ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Class A,1965 Edition through Summer 1966 Addenda.

Steam Generators

As shown in UFSAR Table 4.1-9, the original steam generator components were designed and analyzed to the 1965 ASME Boiler and Pressure Vessel Code through 1965 Addenda. All of the replacement components were constructed in accordance with the 1974 ASME Code through Summer 1976 Addenda. The replacement girth welds are designed in accordance with the 1977 Code (Sections III and IX) through Summer 1978 Addenda.

Reactor Coolant Pumps

The reactor coolant pumps are vertical, single stage, centrifugal, shaft seal pumps. The reactor coolant pump casings had no applicable design code, but were designed per ASME Boiler and Pressure Vessel Code, Section III, Article 4.

The current 60-year fatigue CUFs for critical locations of the PTN Units 3 and 4 Nuclear Steam Supply System (NSSS) components are presented in Table 4.3-1. This table was prepared using the CUF values for reactor vessel and reactor coolant pump components presented in the PTN UFSAR Tables 4.3-2 and 4.3-2a, respectively, and the CUF values for the other Class 1 component locations submitted as part of the EPU LAR (Reference 4.3.6.2). These CUF values were determined using design cycles that were specified as part of the original plant design. These design cycles were intended to be conservative and bounding for all foreseeable plant operational conditions. The design cycles were subsequently utilized in the design stress reports for various NSSS components satisfying ASME fatigue usage design requirements. Design cycles are identified in UFSAR Tables 4.1-8 and 4.1-10.

Experience has shown that actual plant operation is conservatively represented by these design cycles. The use of actual operating history data allows the quantification of these conservatisms in the existing fatigue analyses. To demonstrate that the Class 1 component fatigue analyses remain valid for the SPEO, the design cycles applicable to the Class 1 components from the UFSAR were reviewed.

The actual frequency of occurrence for the design cycles was determined and projections of the number of design cycles for both PTN units to 80 years of operation were made using the average accumulation rate to-date and a shorter-term average accumulation rate. Because the accumulation behavior of more recent plant operations is expected to be a better predictor of future operation, it is weighted more heavily than earlier periods. In the projections shown in the tables that follow, the shorter-term weight is assumed to be a value of 3 for cycles that have occurred most recently, compared to a weighted value of 1 for the longer-term rate for cycles that occurred for the entire plant operating history prior to the last 10 years. This approach is more conservative compared to assuming a bi-linear method that applies the shorter-term rate to all future years in that it accounts for small deviations from the most recent operating experience. The future projected cycles to 80 years are added to the latest available cycle counts (last updated in July 2016) and compared to the design cycle set in Tables 4.3-2 and 4.3-3. Details of the evaluation of projected cycles for PTN Units 3 and 4 for 80 years is documented in a technical report (Section 3.1 of Reference 4.3.6.1) which is included in Enclosure 4 (non-proprietary) and Enclosure 5 (proprietary).

With regard to transient severity, the evaluation in Section 3.2 of Reference 4.3.6.1 confirmed that the existing design transients bound the projected 80-year operation at both units. The RCS component transient analyses were compared to the actual transients experienced at PTN. The evaluation includes an assessment of the transient severity for heatup and cooldown events, which demonstrated that the design-basis transients bound the actual operating practices.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The ASME Boiler and Pressure Vessel Code, Section III, Class 1 fatigue calculations remain valid for the SPEO. The results demonstrate that the number of assumed design cycles will not be exceeded in 80 years of plant operation. PTN will monitor design cycles using the Fatigue Monitoring AMP described in Section B.2.2.1 and assure that corrective action specified in the program is taken if any of the actual design cycles approach 80 percent of their analyzed numbers during the SPEO.

Table 4.3-1
PTN Unit 3 and Unit 4 60-Year Fatigue Cumulative Usage Factors for Reactor Coolant System Components

Component	Cumulative Usage	Allowable
Reactor Vessel		
Head flange	0.083(1)	1.0
Vessel flange	0.531(1)	1.0
Stud bolts	0.81(1)	1.0
Outlet nozzles	0.063(1)	1.0
Inlet nozzles	0.066(1)	1.0
Core support pads	0.020(1)	1.0
Shell at core support pads	0.509(1)	1.0
Bottom head to shell juncture	0.023(1)	1.0
Bottom-mounted instrumentation nozzles	0.002(1)	1.0
Shell to shell juncture	0.034(1)	1.0
Vent nozzle	0.490(2)	1.0
CRDM housing J-weld	0.730(1)	1.0
CRDM housing bi-metallic weld	0.620(2)	1.0
CRDM latch housing	[ ](2)	1.0
CRDM rod travel housing	[ ](2)	1.0
CRDM cap	[ ](2)	1.0
CRDM lower joint	[ ](2)	1.0
CRDM middle joint	[ ](2)	1.0
CRDM upper joint	[ ](2)	1.0
Reactor Vessel Internals		
Upper support plate	[ ](2)	1.0
Deep beam	[ ](2)	1.0
Upper core plate	[ ](2)	1.0
Upper core plate alignment pins	[ ](2)	1.0
Upper support columns	[ ](2)	1.0
Lower support plate	[ ](2)	1.0
Lower support plate to core barrel weld	[ ](2)	1.0
Lower core plate	[ ](2)	1.0
Lower support columns	[ ](2)	1.0
Core barrel flange	[ ](2)	1.0
Core barrel outlet nozzle	[ ](2)	1.0
Radial keys and clevis insert assembly	[ ](2)	1.0

Table 4.3-1
PTN Unit 3 and Unit 4 60-Year Fatigue Cumulative Usage Factors for Reactor Coolant System Components (Continued)

Component	Cumulative Usage	Allowable
Steam Generator		
Divider plate	[ ](2)	1.0
Primary chamber, tubesheet and stub barrel complex	[ ](2)	1.0
Tube-to-tubesheet weld	[ ](2)	1.0
Tubes	[ ](2)	1.0
Upper shell drain	[ ](2)	1.0
Feedwater nozzle	[ ](2)	1.0
Secondary manway bolts	[ ](2)	1.0
Upper shell remnants	[ ](2)	1.0
Secondary hand-hole and inspection port	[ ](2)	1.0
Steam outlet nozzle flow limiters	[ ](2)	1.0
Reactor Coolant Pump		
Casing	< 0.001(3)	1.0
Main flange	0.025(3)	1.0
Main flange studs	0.29(3)	1.0
Pressurizer		
Spray nozzle	[ ](2)	1.0
Upper head	[ ](2)	1.0
Surge nozzle	[ ](2)	1.0
Safety and relief nozzle	[ ](2)	1.0
Support skirt and flange	0.0165(2)	1.0
Lower head	[ ](2)	1.0
Heater well	[ ](2)	1.0
Manway – pad	[ ](2)	1.0
Manway – welded diaphragm	[ ](2)	1.0
Instrument nozzle	[ ](2)	1.0
Immersion heater	[ ](2)	1.0

Notes for Table 4.3-1

1. From UFSAR Table 4.3-2.
2. From fatigue analysis performed for the EPU but not included in the UFSAR.
3. From UFSAR Table 4.3-2a.

Table 4.3-2
PTN Unit 3 — Projected and Analyzed Transient Cycles

Transient Name	Design Cycles	Cycles as of 2016	Projected Cycles for 80 Years	Percent of Design Cycles
Reactor Coolant System				
Station heatup at 100°F per hour[1]	200	109	164	82
Heatup cycles at ≤ 100°F/h, heatup cycle – T_{avg} from ≤ 200°F to ≥ 550°F[2]				
Station cooldown at 100°F per hour[1]	200	109	164	82
Cooldown cycles at ≤ 100°F/h, cooldown cycle – T_{avg} from ≥ 550°F to ≤ 200°F[2]				
Pressurizer cooldown cycles at 200°F/h from nominal pressure, pressurizer cooldown cycle temperatures from ≥ 650°F to ≤ 200°F[2]	200[3]	95	148	74
Pressurizer cooldown cycles at 200°F/hour from 400 psia, pressurizer cooldown cycle temperatures from ≥ 650°F to ≤ 200°F[2]	200[3]	95	148	74
Loss of load cycles, without immediate turbine or reactor trip (≥ 15% of rated thermal power to 0% of rated thermal power) [2]	80	15	28	35
Station loading at 5% of full power/min[1]	14,500[4]	293	533	24[4]
Station unloading at 5% of full power/min[1]	14,500[4]	242	440	20[4]
Step load increase of 10% of full power (but not to exceed full power) [1]	2000	43	79	4
Step load decrease of 10% of full power[1]	2000	90	164	8
Step load decrease of 50% of full power[1]	200	68	82	41
Reactor trip cycles[1][2]	400	183	272	68
Hydrostatic test at 3107 psig pressure, 100°F temperature[1]	1[5]	1	1	100
Hydrostatic pressure test at 2485 psig pressure and 400°F temperature[1][2]	5[6]	1	2	40
Steady state fluctuations[1]	NA[7]	-	-	-
Feedwater cycling at hot standby[1]	2000[8]	-	-	-
Loss-of-offsite AC electrical power[2]	40	6	10	25
Loss of flow in one reactor coolant loop[1][2]	80	14	26	33
Inadvertent auxiliary spray[2]	10	0	1	10

Table 4.3-2
PTN Unit 3 — Projected and Analyzed Transient Cycles (Continued)

Transient Name	Design Cycles	Cycles as of 2016	Projected Cycles for 80 Years	Percent of Design Cycles
Primary to secondary side leak tests (pressurized to 2435 psig)(2)	150	1	2	1
Primary to secondary side leak tests (pressurized to 2250 psig)(2)	15(9)	1	2	13
Secondary Coolant System				
Hydrostatic pressure tests (pressurized to 1085 psig)(2)	50(9)	SG A – 9 SG B – 7 SG C – 7	SG A – 21 SG B – 16 SG C – 16	SG A – 42 SG B – 32 SG C – 32
Hydrostatic pressure tests (pressurized to 1356 psig)(2)	10(10)	SG A – 9(11) SG B – 7(11) SG C – 7(11)	SG A – 9(12) SG B – 7(12) SG C – 7(12)	SG A – 90 SG B – 70 SG C – 70
Secondary to primary side leak tests (pressurized to 840 psig)(2) (13)	15(9)	SG A – 8 SG B – 15 SG C – 9	SG A – 8 SG B – 15 SG C – 9	SG A – 53 SG B – 100 SG C – 60

Notes for Table 4.3-2

1. Table 4.1-8 of the UFSAR.
2. Table 4.1-10 of the UFSAR.
3. Applies to pressurizer only.
4. The loading and unloading design cycle limit for baffle-former bolts only is being lowered from 14,500 to 2,200 due to EPU reactor coolant conditions.
5. Limited by steam generator analysis. Represents pre-operational hydrostatic test (shop hydrotest).
6. Limited by reactor coolant pump analysis.
7. Not counted, not significant contributor to fatigue usage factor.
8. Not counted, intermittent slug feeding at hot standby not performed.
9. Applies to steam generator only.
10. Original design cycles was 50. Reduced to 10 as part of an administrative change associated with EPU.
11. Cycles counted from post steam generator replacement.
12. No additional design cycles expected.
13. This test is no longer performed.

Table 4.3-3
PTN Unit 4 — Projected and Analyzed Transient Cycle

Transient Name	Design Cycles	Cycles as of 2016	Projected Cycles for 80 Years	Percent of Design Cycles
Reactor Coolant System				
Station heatup at 100°F per hour[1]	200	121	181	91
Heatup cycles at ≤ 100°F/h, heatup cycle – T_{avg} from ≤ 200°F to ≥ 550°F[2]				
Station cooldown at 100°F per hour[1]	200	121	181	91
Cooldown cycles at ≤ 100°F/h, cooldown cycle – T_{avg} from ≥ 550°F to ≤ 200°F[2]				
Pressurizer cooldown cycles at 200°F/h from nominal pressure, pressurizer cooldown cycle temperatures from ≥ 650°F to ≤ 200°F[2]	200[3]	104	158	79
Pressurizer cooldown cycles at 200°F/hour from 400 psia, pressurizer cooldown cycle temperatures from ≥ 650°F to ≤ 200°F[2]	200[3]	104	158	79
Loss of load cycles, without immediate turbine or reactor trip (≥ 15% of rated thermal power to 0% of rated thermal power) [2]	80	14	27	34
Station loading at 5% of full power/min[1]	14,500[4]	260	484	22[4]
Station unloading at 5% of full power/min[1]	14,500[4]	242	451	21[4]
Step load increase of 10% of full power (but not to exceed full power) [1]	2000	44	82	4
Step load decrease of 10% of full power[1]	2000	57	107	5
Step load decrease of 50% of full power[1]	200	42	51	26
Reactor trip cycles[1][2]	400	187	292	73
Hydrostatic test at 3107 psig pressure, 100°F temperature[1]	1[5]	1	1	100
Hydrostatic pressure test at 2485 psig pressure and 400°F temperature[1][2]	5[6]	1	2	40
Steady state fluctuations[1]	NA[7]	-	-	-
Feedwater cycling at hot standby[1]	2000[8]	-	-	-
Loss-of-offsite AC electrical power[2]	40	13	19	48
Loss of flow in one reactor coolant loop[1][2]	80	11	21	26
Inadvertent auxiliary spray[2]	10	0	1	10

Table 4.3-3
PTN Unit 4 — Projected and Analyzed Transient Cycle (Continued)

Transient Name	Design Cycles	Cycles as of 2016	Projected Cycles for 80 Years	Percent of Design Cycles
Primary to secondary side leak tests (pressurized to 2435 psig)(2)	150	1	2	1
Primary to secondary side leak tests (pressurized to 2250 psig)(2)	15(9)	1	2	13
Secondary Coolant System				
Hydrostatic pressure tests (pressurized to 1085 psig)(2)	50(9)	SG A – 6 SG B – 6 SG C – 5	SG A – 14 SG B – 14 SG C – 12	SG A – 28 SG B – 28 SG C – 24
Hydrostatic pressure tests (pressurized to 1356 psig)(2)	10(10)	SG A – 6(11) SG B – 6(11) SG C – 5(11)	SG A – 6(12) SG B – 6(12) SG C – 5(12)	SG A – 60 SG B – 60 SG C – 50
Secondary to primary side leak tests (pressurized to 840 psig)(2) (13)	15(9)	SG A – 14 SG B – 15 SG C – 15	SG A – 14 SG B – 15 SG C – 15	SG A – 93 SG B – 100 SG C – 100

<u>Notes for Table 4.3-3</u>

1. Table 4.1-8 of the UFSAR.
2. Table 4.1-10 of the UFSAR.
3. Applies to pressurizer only.
4. The loading and unloading design cycle limit for baffle-former bolts only is being lowered from 14,500 to 2,200 due to EPU reactor coolant conditions.
5. Limited by steam generator analysis. Represents pre-operational hydrostatic test (shop hydrotest).
6. Limited by reactor coolant pump analysis.
7. Not counted, not significant contributor to fatigue usage factor.
8. Not counted, intermittent slug feeding at hot standby not performed.
9. Applies to steam generator only.
10. Original design cycles was 50. Reduced to 10 as part of an administrative change associated with EPU.
11. Cycles counted from post steam generator replacement.
12. No additional design cycles expected.
13. This test is no longer performed.

4.3.2 Metal Fatigue of Piping Components

TLAA Description

This section addresses metal fatigue of piping and fittings associated with the following systems:

- Reactor coolant
- Residual heat removal
- Chemical and volume control
- Primary sampling
- Secondary sampling
- Emergency diesel generator air (diesel exhaust)
- Main steam and turbine
- Feedwater and blowdown
- Auxiliary feedwater and condensate storage (steam supply)
- Auxiliary steam
- Condensate

The reactor coolant system primary loop piping and balance-of-plant piping systems listed above are designed to the requirements of ANSI B31.1, Power Piping. The exceptions are the PTN Units 3 and 4 pressurizer surge lines and the PTN Unit 4 emergency diesel generator safety-related piping.

The pressurizer surge lines have been designed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 1 and are addressed in Section 4.3.1. The Unit 4 emergency diesel generator safety-related piping has been designed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 3, which are comparable to ANSI B31.1 design requirements. The evaluation of the Unit 4 emergency diesel generator safety-related piping metal fatigue is, therefore, included in this section.

Piping and components designed in accordance with ANSI B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in a simplified manner in the design process. The code first requires prediction of the overall number of thermal and pressure cycles expected during the lifetime of these components. Then a stress range reduction factor is determined for that number of cycles using a table from the applicable design code, similar to Table 4.3.2-1 below. If the total number of cycles is 7,000 or less, the stress range reduction factor is 1.0, which when applied, would not reduce the allowable stress value.

The assessments of fatigue for these piping systems are considered to be implicit fatigue analyses since they are based upon cycles anticipated for the life of the component, and are therefore, TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

Design requirements in ANSI B31.1 assume a stress range reduction factor to provide conservatism in the piping design to account for fatigue due to thermal cyclic operation. The cyclic qualification of the piping per ANSI B31.1 is based on the number of equivalent full temperature cycles as listed in Table 4.3.2-1.

Table 4.3.2-1
Stress Range Reduction Factors for ANSI B31.1 Piping

Number of Equivalent Full Temperature Cycles	Stress Range Reduction Factor
7,000[1] 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

Notes for Table 4.3.2-1

1. This value is for piping. In accordance with ANSI B31.1, the value for tubing is 14,000 cycles.

This reduction factor is 1.0 provided the number of anticipated cycles is limited to 7000 equivalent full temperature cycles for piping and 14,000 cycles for tubing. A review of the ANSI B31.1 piping within the scope of SLR was performed in order to identify those systems that operate at elevated temperature and to establish a conservative number of projected cycles based on 80 years of operation. Typically, these piping and tubing systems are subject to continuous steady-state operation and experience temperature cycling only during plant heatup and cooldown, during plant transients, or during periodic testing.

From the EPRI Report TR-104534, “Fatigue Material Handbook” Volume 2, Section 4 (Reference 4.3.6.3), piping and tubing systems subject to thermal fatigue due to temperature cycling are described as, “For initial screening, systems in which the fluid temperature can vary more than 200°F in austenitic steel components and more than 150°F in carbon and low alloy steel components are potentially of concern for fatigue due to thermal transients. Thus, carbon steel systems or portions of systems with operating temperatures less than 220°F and stainless steel systems or portions of systems with operating temperatures less than 270°F may generally be excluded from such concerns, since room temperature represents a practical minimum exposure temperature for most plant systems.”

For PTN, any system or portions of systems with operating temperatures above 220°F are conservatively evaluated for fatigue. The piping and tubing systems requiring evaluation for SLR are listed in Table 4.3.2-2 below.

Once a system is established to operate at a temperature above 220°F, system operating characteristics are established, and a determination is made as to whether the system is expected to exceed 7000 (14,000 for tubing) full temperature cycles in 80 years of operation. In order to exceed 7000 cycles a system would be required to heatup and cooldown approximately once every four days. For the systems that are subjected to elevated temperatures above the fatigue threshold, a calculation was performed to determine a conservative number of projected full temperature cycles for 80 years of plant operation for the piping, tubing and in-line components. These projections, which are presented in Table 4.3.2-2, indicate that 7000 thermal cycles will not be exceeded for 80 years of operation with the exception of the reactor coolant system B hot leg sample tubing portion of primary sampling.

Table 4.3.2-2
Projected Number of Full Temperature Cycles

System	Number of Projected Cycles
Reactor coolant	200
Residual heat removal	400
Chemical and volume control	200
Primary sampling (only tubing is exposed to the temperature cycles)	(1)
Secondary sampling	200
Emergency diesel generator air (diesel exhaust)	1680
Main steam and turbine	200
Feedwater and blowdown	200
Auxiliary feedwater and condensate storage (steam supply)	5760
Auxiliary steam	200
Condensate	200
Feedwater heater drains and vents	200

<u>Note for Table 4.3.2-2</u>

1. See further discussion of the primary sampling below.

For the B hot leg tubing, whose design thermal cycle limit is < 14,000 full temperature cycles, the design thermal cycle limit could be reached at the end of 2018 based on current operation. In order to ensure that the tubing can continue to perform its function for the current PEO as well as the SPEO, one of the following actions needs to be completed:

(1) Implement a procedure change to ensure that an alternate sample path is used for reactor coolant system sampling to limit cycles on the B hot leg sample tubing.

(2) Review the stress analysis or reanalyze to determine if the tubing design has margin for a reduction in the thermal fatigue usage factor.

(3) Perform NDE of the tubing to document that no fatigue cracking or other failures exists. This inspection will need to be repeated periodically over the life of the system to demonstrate that fatigue cracking has not occurred.

(4) Replace the tubing.

The above actions have been included in the PTN corrective action program and require resolution prior to the end of 2018.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The ASME Section III, Class 3 and ANSI B31.1 allowable stress calculations remain valid for the SPEO. The results demonstrate that the number of assumed thermal cycles will not be exceeded in 80 years of plant operation. Note that if aging management is selected for addressing fatigue of the primary sampling tubing, the TLAA disposition will be modified to 10 CFR 54.21(c)(1)(iii).

4.3.3 <u>Environmentally Assisted Fatigue</u>

TLAA Description

The current PTN approach to environmentally assisted fatigue (EAF) is described in UFSAR Section 16.3.2.5. The results of NUREG/CR-6260 analyses were utilized to scale up the PTN plant-specific design fatigue cumulative usage factors for the same locations to account for environmental effects. Generic industry studies performed by EPRI and NEI were also considered in this aspect of the evaluation, as well as environmental data that had been collected and published subsequent to the generic industry studies. Additional EAF evaluations were undertaken for some components in 2010 as part of the extended power uprate. These EAF evaluations used actual projected cycle counts for the reactor pressure vessel outlet nozzles, the reactor pressure vessel shell at core support pads, and the pressurizer spray nozzles. Additionally, more refined fatigue evaluations using the ANSYS computer program were applied as summarized in UFSAR Section 16.3.2.5. All the projected environmentally assisted CUFs (CUF_{en}s) are maintained less than 1.0 for all applicable reactor coolant pressure boundary components with the exception of the pressurizer surge lines. In lieu of additional analyses to refine the CUF_{en} for the pressurizer surge lines, PTN selected aging management to address pressurizer surge line fatigue during the current PEO.

Demonstrating that reactor coolant pressure boundary components have a CUF_{en} less than or equal to the design limit of 1.0 is an acceptable option for managing environmentally assisted fatigue (EAF) for the reactor coolant pressure boundary. Considering the calculation of fatigue usage factors is part of the CLB and is used to support safety determinations, and the number of occurrences of each transient type was based upon 60-year assumptions, these Class 1 fatigue analyses have been identified as TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

NUREG-2192, Revision 0 (Reference 4.3.6.4), provides a recommendation for evaluating the effects of the reactor water environment on the fatigue life of ASME Section III Class 1 components that contact reactor coolant to support closure of Generic Safety Issue 190 (References 4.3.6.5 and 4.3.6.6). NUREG-2192, Revision 0 (Reference 4.3.6.4) indicates that applicants should include CUF_{en} calculations for the limiting reactor coolant pressure boundary component locations exposed to the reactor water environment. This sample set includes the locations identified in NUREG/CR-6260 (Reference 4.3.6.7) and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. Plant-specific justification can be provided to demonstrate that calculations for the NUREG/CR-6260 locations do not need to be included.

The PTN EAF assessment for SLR was performed using the applicable guidance from NUREG-2192, Revision 0 (Reference 4.3.6.4). Section 4.3.2.1.2.1, "10 CFR 54.21(c)(1)(i)," of NUREG-2192, Revision 0 (Reference 4.3.6.4) for components evaluated for CUF_{en} states the following:

> The existing CUF_{en} calculations remain valid for the subsequent period of extended operation because the number of accumulated cycles, the assumed severity of the cyclic loadings, and the assumed water chemistry conditions evaluated in the calculations are not projected to exceed the limits evaluated for these parameters. The revised projections for the number of accumulated cycles are verified to be consistent with historical plant operating characteristics and anticipated future operation.
>
> A plant-specific justification can be provided to demonstrate that existing CUF_{en} calculations performed using guidance in Section 4.3.2.1.3 of NUREG-1800, Revision 2 will remain valid for the subsequent period of extended operation and are sufficiently conservative when compared to those CUF_{en} calculations that would be generated using the guidance in RG 1.207, Revision 1, or in NUREG/CR-6909, Revision 0 (with "average temperature" used consistent with the clarification that was added to NUREG/CR-6909, Revision 1).

PTN's approach for SLR was to generate CUF_{en} calculations using the guidance in NUREG/CR-6909, Revision 0 (Reference 4.3.6.31) (with "average temperature" used consistent with the clarification that was added to NUREG/CR-6909, Revision 1 (Reference 4.3.6.11)).

Per NUREG-2192, Revision 0 (Reference 4.3.6.4)., the EAF assessment for SLR should include the NUREG/CR-6260 locations and other plant-specific locations that may be more limiting than those locations evaluated in NUREG/CR-6260 for the appropriate vintage and PWR design. For PTN, the older-vintage Westinghouse PWR plant is applicable; in fact, the "Older Vintage Westinghouse Plant" evaluated in Section 5.5 of NUREG/CR-6260 is directly relevant to PTN because the codes, analytical approach and techniques used for that plant matches those used for PTN. In addition, the evaluated transient cycles matched or bounded PTN. The critical fatigue-sensitive component locations chosen in NUREG/CR-6260 for the early-vintage Westinghouse plant are:

- Reactor vessel shell and lower head
- Reactor vessel inlet and outlet nozzles
- Pressurizer surge line (including the pressurizer and hot leg nozzles)
- Reactor coolant system piping charging system nozzle
- Reactor coolant system piping safety injection nozzle
- Residual heat removal system Class 1 piping

Based on the foregoing discussion, the updated SLR EAF assessment for PTN was performed as follows:

- The plant-specific NUREG/CR-6260 locations were reevaluated for SLR.

- To ensure that any locations that may be more limiting than the NUREG/CR- 6260 locations were addressed, all of the reactor coolant pressure boundary components with existing ASME Code fatigue analyses CUFs presented in Table 4.3-1 were evaluated for EAF for SLR.

- The revised plant-specific EAF multipliers applicable for SLR were calculated based on the latest F_{en} methods using the guidance in NUREG/CR-6909, Revision 0 (Reference 4.3.6.31) (with "average temperature" used consistent with the clarification that was added to NUREG/CR-6909, Revision 1 (Reference 4.3.6.11).

Per NUREG-2192, Revision 0 (Reference 4.3.6.4), Sections 4.3.2.1.2 and 4.3.3.1.2, applicants are to include EAF evaluations for "component locations that are part of the reactor coolant pressure boundary." Additionally, only components exposed to the reactor coolant water environment need to be evaluated. Thus, as an initial step of the PTN EAF evaluation, the NUREG/CR-6260 locations and the components presented in Table 4.3-1 were reviewed to determine if they were (1) part of the reactor coolant pressure boundary, and (2) exposed to the reactor coolant water environment. The results are presented in Table 4.3.3-1 below.

Table 4.3.3-1
Components Requiring an EAF Evaluation

Component	Reactor Coolant Pressure Boundary?	Exposed to Reactor Coolant?	EAF Evaluation Required?
NUREG/CR-6260 Locations(1)			
Surge line hot leg nozzle	Yes	Yes	Yes
Safety injection nozzle	Yes	Yes	Yes
Residual heat removal (RHR) piping	Yes	Yes	Yes
Charging nozzle	Yes	Yes	Yes
Reactor Vessel			
Head flange	Yes	Yes	Yes
Vessel flange	Yes	Yes	Yes
Stud bolts	Yes	No	No
Outlet nozzles	Yes	Yes	Yes
Inlet nozzles	Yes	Yes	Yes
Core support pad	Yes	Yes	Yes
Shell at core support pads	Yes	Yes	Yes
Bottom head to shell juncture	Yes	Yes	Yes
Bottom-mounted instrumentation nozzles	Yes	Yes	Yes
Shell to shell juncture	Yes	Yes	Yes
Vent nozzle	Yes	Yes	Yes
CRDM housing J-weld	Yes	Yes	Yes
CRDM housing bi-metallic weld	Yes	Yes	Yes
CRDM latch housing	Yes	Yes	Yes
CRDM rod travel housing	Yes	Yes	Yes
CRDM cap	Yes	Yes	Yes
CRDM lower joint	Yes	Yes	Yes
CRDM middle joint	Yes	Yes	Yes
CRDM upper joint	Yes	Yes	Yes
Head flange	Yes	Yes	Yes
Vessel flange	Yes	Yes	Yes

Table 4.3.3-1
Components Requiring an EAF Evaluation (Continued)

Component	Reactor Coolant Pressure Boundary?	Exposed to Reactor Coolant?	EAF Evaluation Required?
Reactor Vessel Internals			
Upper support plate	No	Yes	No
Deep beam	No	Yes	No
Upper core plate	No	Yes	No
Upper core plate alignment pins	No	Yes	No
Upper support columns	No	Yes	No
Lower support plate	No	Yes	No
Lower support plate to core barrel weld	No	Yes	No
Lower core plate	No	Yes	No
Lower support columns	No	Yes	No
Core barrel flange	No	Yes	No
Core barrel outlet nozzle	No	Yes	No
Radial keys and clevis insert assembly	No	Yes	No
Steam Generator			
Divider plate	Yes	Yes	Yes
Primary chamber, tubesheet and stub barrel complex	Yes	Yes	Yes
Tube-to-tubesheet weld	No	Yes	No
Tubes	Yes	Yes	Yes
Upper shell drain	No	No	No
Feedwater nozzle	No	No	No
Secondary manway bolts	No	No	No
Upper shell remnants	No	No	No
Secondary hand-hole and inspection port	No	No	No
Steam outlet nozzle flow limiters	No	No	No
Reactor Coolant Pump			
Casing	Yes	Yes	Yes
Main flange	Yes	Yes	Yes
Main flange studs	Yes	No	No

Table 4.3.3-1
Components Requiring an EAF Evaluation (Continued)

Component	Reactor Coolant Pressure Boundary?	Exposed to Reactor Coolant?	EAF Evaluation Required?
Pressurizer			
Spray nozzle	Yes	Yes	Yes
Upper head	Yes	Yes	Yes
Surge nozzle	Yes	Yes	Yes
Safety and relief nozzle	Yes	Yes	Yes
Support skirt and flange	Yes	Yes	Yes
Lower head	Yes	Yes	Yes
Heater well	Yes	Yes	Yes
Manway – pad	Yes	Yes	Yes
Manway – welded diaphragm	Yes	Yes	Yes
Instrument nozzle	Yes	Yes	Yes
Immersion heater	Yes	Yes	Yes

Note for Table 4.3.3-1

1. The reactor vessel NUREG/CR-6260 locations are captured under the reactor vessel listing.

The next step in the PTN EAF evaluation process was to apply bounding EAF multipliers (F_{en}) to the existing ASME Code fatigue analyses CUFs associated with the components requiring EAF evaluation from Table 4.3.3-1. These multipliers were developed based on the NUREG/CR-6909, Revision 0 (Reference 4.3.6.31)(with "average temperature" used consistent with the clarification that was added to NUREG/CR-6909, Revision 1 (Reference 4.3.6.11)), and PTN plant-specific reactor coolant system chemistry. The specific details regarding the development of these multipliers is provided in Appendix A of Reference 4.3.6.8, which is included in Enclosure 4 (non-proprietary) and Enclosure 5 (proprietary). In cases where the materials were not known, F_{en} values for all three F_{en} material groupings (carbon and low alloy steels, stainless steels, and nickel alloys) were determined and the maximum multiplier was used.

The results of these calculations are presented in Table 4.3.3-2 below. If the CUF_{en} for a particular reactor coolant pressure boundary component is less than 1.0 after this step, identified as CUF_{en} Screening in the table, the component is acceptable for EAF for the SPEO.

Table 4.3.3-2
80-Year Environmentally Assisted Fatigue CUFs

Component	Material Type	Design CUF	F_{en}(1)	CUF_{en} Screening
NUREG/CR-6260 Locations(2)				
Surge line hot leg nozzle	Stainless steel	0.944	(3)	(3)
Safety injection nozzle	Stainless steel	0.046	14.06	0.647
Residual heat removal (RHR) piping	Stainless steel	0.022	14.06	0.309
Charging nozzle	Stainless steel	0.030	14.06	0.422
Reactor Vessel				
Head flange	Carbon steel, stainless steel clad	0.083	6.276	0.521
Vessel flange	Carbon steel, stainless steel clad	0.531	6.276	**3.333**
Outlet nozzles	Carbon steel, stainless steel clad and safe end	0.063	2.45	0.154
Inlet nozzles	Carbon steel, stainless steel clad and safe end	0.066	2.45	0.162
Core support pads	Inconel, alloy 600	0.020	3.75	0.075
Shell at core support pads	Carbon steel with Inconel clad	0.509	4.77	**2.428**
Bottom head to shell juncture	Carbon steel, stainless steel clad	0.023	14.06	0.323
Bottom-mounted instrumentation nozzles	Stainless steel	0.002	14.06	0.028
Shell-to-shell juncture	Carbon steel, stainless steel clad	0.034	14.06	0.478
Vent nozzle	Inconel, alloy 690	0.490	3.75	**1.838**
CRDM housing J-weld	Nickel alloy	0.730	3.75	**2.738**
CRDM housing bi-metallic weld	Nickel alloy	0.620	3.75	**2.323**
CRDM latch housing	Stainless steel	[ ]	14.06	**[ ]**
CRDM rod travel housing	Stainless steel	[ ]	14.06	[ ]
CRDM cap	Stainless steel	[ ]	14.06	[ ]
Middle joint	Stainless steel	[ ]	14.06	[ ]
Upper joint	Stainless steel	[ ]	14.06	[ ]
Lower joint	Stainless steel	[ ]	14.06	**[ ]**

Table 4.3.3-2
80-Year Environmentally Assisted Fatigue CUFs (Continued)

Component	Material Type	Design CUF	F_{en} (1)	CUF_{en} Screening
Steam Generators (Primary Side)				
Primary chamber, tubesheet and stub barrel complex	Carbon steel, alloy 600 and stainless steel clad	[ ]	6.276	[ ]
Divider plate	Inconel	[ ]	3.75	**[ ]**
Tubes	Inconel, alloy 600 thermally treated	[ ]	3.75	**[ ]**
Reactor Coolant Pumps				
Casing	Stainless steel	< 0.001	14.06	0.014
Main flange	Stainless steel	0.025	14.06	0.351
Pressurizer				
Spray nozzle	Carbon steel with stainless steel clad and safe end	[ ]	14.06	**[ ]**
Upper head	Low alloy steel	[ ]	6.28	**[ ]**
Surge nozzle	Stainless steel	[ ]	(3)	(3)
Safety and relief nozzle	Carbon steel, stainless steel clad and safe end	[ ]	14.06	[ ]
Support skirt and flange	Carbon steel	[ ]	6.28	[ ]
Lower head	Carbon steel, stainless steel clad	[ ]	14.06	[ ]
Heater well	Carbon steel, stainless steel clad	[ ]	14.06	**[ ]**
Manway-pad	Carbon steel	[ ]	6.28	[ ]
Manway-welded diaphragm	Nickel alloy	[ ]	3.75	[ ]
Instrument nozzle	Stainless steel	[ ]	14.06	[ ]
Immersion heater	Stainless steel	[ ]	14.06	[ ]

Notes for Table 4.3.3-2

1. F_{en} = environmental multiplier.
2. The reactor vessel NUREG/CR-6260 locations are captured under reactor vessel listing.
3. Managed by the Pressurizer Surge Line Fatigue AMP (Section B.2.4.1).

For locations where CUF_{en} Screening was greater than 1, as identified above highlighted in yellow with bold print, additional analyses were performed in order to reduce the CUF_{en} to less than 1. These additional analyses are further described below and provided in detail in the references noted below, copies of which are provided in Enclosure 4 (non-proprietary) and Enclosure 5 (proprietary).

Reactor Vessel Flange – CUF_{en} Screening = 3.333

A revised CUF_{en} was calculated by performing a more refined analysis and crediting 80-year projected design cycles for plant heatup, cooldown, loading, unloading, and rapid power increases and decreases.

CUF_{en} Final = 0.373 Reference 4.3.6.25

Reactor Vessel Shell at Core Support Pads – CUF_{en} Screening = 2.428

A revised CUF_{en} was calculated by crediting 80-year projected design cycles for the hydrostatic test at 2485 psig pressure and 400°F temperature.

CUF_{en} Final = 0.910 Reference 4.3.6.19

Reactor Vessel Vent Nozzle – CUF_{en} Screening = 1.838

A revised CUF_{en} was calculated by performing a finite element fatigue calculation using the methodology of Subarticle NB-3200 of Section III of the ASME Code.

CUF_{en} Final = 0.230 Reference 4.3.6.24

CRDM Housing J-Weld – CUF_{en} Screening = 2.738

A revised CUF_{en} was calculated by performing a more refined analysis and crediting 80-year projected design cycles for plant heatup, cooldown, loading, unloading, and rapid power increases and decreases.

CUF_{en} Final = 0.274 Reference 4.3.6.22

CRDM Housing Bi-metallic Weld – CUF_{en} Screening = 2.323

A revised CUF_{en} was calculated by performing a more refined analysis and crediting 80-year projected design cycles for plant heatup, cooldown, and reactor trips.

CUF_{en} Final = 0.695 Reference 4.3.6.21

CRDM Latch Housing – CUF_{en} Screening = [ ]

A revised CUF_{en} was calculated by performing a more refined analysis and crediting 80-year projected design cycles for plant heatup, plant loading and reactor trips.

CUF_{en} Final = 0.269 Reference 4.3.6.23

CRDM Lower Joint – CUF_{en} Screening = [ ]

A revised CUF_{en} was calculated by performing a more refined analysis and crediting 80-year projected design cycles for plant heatup, 10% step load increases, 50% step load decreases, loss of load, loss of AC power, and reactor trips (Unit 4 only).

CUF_{en} Final = 0.749 Reference 4.3.6.26

Steam Generator Divider Plate - CUF_{en} Screening = [ ]

A revised CUF_{en} was calculated by crediting 80-year projected design cycles for plant heatup and cooldown, loading and unloading and 10% step load increases and decreases.

CUF_{en} Final = 0.881 Reference 4.3.6.20

Steam Generator Tubes – CUF_{en} Screening = [ ]

A revised CUF_{en} was calculated by crediting 80-year projected design cycles for plant heatup and cooldown, loading and unloading and 10% step load increases and decreases.

CUF_{en} Final = 0.903 Reference 4.3.6.20

Pressurizer Spray Nozzle – CUF_{en} Screening = [ ]

A revised CUF_{en} was calculated by performing a finite element fatigue calculation using the methodology of Subarticle NB-3200 of Section III of the ASME Code and projected design cycles for plant heatup and cooldown.

CUF_{en} Final = 0.529 Reference 4.3.6.29

Pressurizer Upper Head – CUF_{en} Screening = [ ]

A revised CUF_{en} was calculated by crediting 80-year projected design cycles for plant loading, unloading, and boron concentration equalization transients.

CUF_{en} Final = 0.974 Reference 4.3.6.19

Heater Well – CUF_{en} Screening = [ ]

A revised CUF_{en} was calculated by performing a finite element fatigue calculation using the methodology of Subarticle NB-3200 of Section III of the ASME Code and projected design cycles for plant heatup and cooldown.

CUF_{en} Final = 0.093 Reference 4.3.6.28

As described above, the projected environmentally assisted CUFs (CUF_{en}s) are maintained less than 1.0 for all applicable reactor coolant pressure boundary components with the exception of the pressurizer surge lines. In lieu of additional analyses to refine the CUF_{en} for the pressurizer surge lines, PTN has selected aging management to address pressurizer surge line fatigue during the SPEO as is currently done for the PEO. In particular, the potential for crack initiation and growth, including reactor water environmental effects, is adequately managed during the SPEO by the plant-specific PTN Pressurizer Surge Line Fatigue AMP (Section B.2.4.1). The technical basis and conclusions of the current flaw tolerance analysis of the pressurizer surge lines (Reference 4.3.6.12) remain applicable for the SPEO. The surge line inspection approach was submitted to the NRC for review in 2012 (Reference 4.3.6.13), and was subsequently approved by the NRC in 2013 (Reference 4.3.6.14). The flaw tolerance analysis of the pressurizer surge lines establishes inspection frequency for the Pressurizer Surge Line Fatigue AMP; however, the flaw tolerance analysis does not consider the life of the plant and is not a TLAA. In addition, there are no new aging affects requiring management for the pressurizer surge lines during the SPEO. For the SPEO, the effects of EAF for the PTN pressurizer surge line welds will continue to be managed by an inspection program consistent with the Pressurizer Surge Line Fatigue AMP approved by the NRC for the current PEO.

Results of the pressurizer surge line examinations performed to date are presented in Section B.2.4.1.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

For the Class 1 reactor coolant pressure boundary components associated with the reactor vessels, pressurizers, steam generators, and reactor coolant pumps with calculated ASME Section III CUFs, and NUREG/CR-6260 locations, the environmentally assisted fatigue analyses will be managed using the Fatigue Monitoring AMP (Section B.2.2.1) and assure that corrective action specified in the program is taken if any of the actual cycles approach 80 percent of their projected or design analyzed limits, as applicable.

For the pressurizer surge line, PTN will manage the effects of aging due to fatigue on the pressurizer surge line for the SPEO by implementing surface and volumetric examination of the welds using the Pressurizer Surge Line Fatigue AMP (Section B.2.4.1) in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.4 Reactor Vessel Underclad Cracking

TLAA Description

In early 1971, an anomaly identified as grain boundary separation, perpendicular to the direction of the austenitic stainless steel cladding weld overlay, was identified in the heat-affected zone of reactor vessel base metal. To date, no reactor vessel underclad cracking has been detected at PTN. Reactor vessel underclad cracking involves cracks in base metal forgings immediately beneath austenitic stainless steel cladding which are created as a result of the weld-deposited cladding process.

The evaluation was extended to 60 years using fracture mechanics evaluations based on a representative set of design transients with the occurrences extrapolated to cover 60 years of service life. This evaluation was documented in WCAP-15338-A, Rev. 0 (Reference 4.3.6.15).

The 60-year analysis associated with reactor vessel underclad cracking was reviewed to consider EPU conditions. The original evaluation performed a fracture mechanics evaluation based on a representative set of design transients with the occurrences extrapolated to cover 60 years of service life. The representative set of design transients remains unchanged with the implementation of the EPU. As a result, the original analysis associated with reactor vessel underclad cracking was concluded to remain valid with the implementation of the EPU through the current period of extended operation.

Although reactor vessel underclad cracking has not been detected at PTN, the generic evaluation of reactor vessel underclad cracking is part of the current licensing basis and is used to support safety determinations, and the probability of failure was based upon operating history assumptions, this cracking analysis has been identified as a TLAA requiring evaluation for the SPEO.

The Unit 3 and Unit 4 RVCHs were replaced in 2004 and 2005 respectively. During the manufacturing process of the new forging and the cladding process of the replacement heads, precautions were taken to preclude the potential for underclad cracking. These precautions preclude the formation of segregated areas on the surface to be clad, the presence of stresses in the underclad heat affected zone (HAZ), and the presence of coarse grain areas in the cladding HAZ. Thus, underclad cracking of the reactor vessel heads was concluded not to be a TLAA for SLR.

TLAA Evaluation

As summarized in Reference 4.3.6.15, there are many levels of defense in depth relative to the underclad cracks. There is no known mechanism for the creation of additional flaws in this region, so the only concern is the potential propagation of the existing flaws. In 1971, Westinghouse submitted an assessment of the underclad cracking issue to the regulatory authorities, then the Atomic Energy Commission, evaluating underclad cracks for an operating period of 40 years. The Commission reviewed the assessment, and issued the following conclusion:

> We concur with Westinghouse's finding that the integrity of a vessel having flaws such as described in the subject report would not be compromised during the life of the plant. This report is acceptable and may be referenced in future applications where similar underclad grain boundary separations have been detected. However, such flaws should be avoided, and we recommend that future applicants state in their PSARs what steps they plan to take in this regard.

An update to the above evaluation has been prepared, demonstrating that underclad cracks are of no concern relative to structural integrity of the reactor vessel for a period of 80 years (Reference 4.3.6.16). A copy of this evaluation is provided in Enclosure 4.

No reactor vessel underclad cracking has been detected at PTN. However, the following discussion provides summaries of industry operating experience.

Flaw indications indicative of underclad cracks have been evaluated in accordance with the acceptance criteria of the ASME Code Section XI. Such indications have been found during pre-service and inservice inspections of plants considered to have cladding conditions which are suspect with respect to underclad cracking. These flaw indications have been dispositioned as being acceptable for further service without repair or detailed evaluation, because they meet the conservative requirements of the ASME Code Section XI, Paragraph IWB-3500.

Fracture evaluations have also been performed to evaluate underclad cracks, and the results have been that the flaws are acceptable. A number of field examples were summarized which have involved cladding cracks, as well as exposure of the base metal due to cladding removal. In several cases the cladding cracks have been suspected to extend into the base metal, and have been analyzed as such. In these cases the cracks were suspected to be exposed to the water environment, and successive monitoring inspections were conducted on the area of concern. No changes were found due to propagation or further deterioration of any type. The NRC then allowed the surveillance to be discontinued.

Finally, underclad cracks found during pre-service and inservice inspections have been evaluated in accordance with the acceptance criteria of the ASME Code Section XI. The observed underclad cracks are very shallow, confined in depth to less than 0.295 inch and have lengths up to 2.0 inches. The fatigue crack growth assessment for these small cracks shows very little extension over 80 years, even if they were exposed to the reactor water and with crack tip pressure of 2,500 psi. For the worst case scenario, a 0.30 inch deep continuous axial flaw in the beltline region would grow to 0.43 inch after 80 years. The minimum allowable axial flaw size for normal, upset and test conditions is 0.67 inch and for emergency and faulted conditions is 1.25 inches. Since the allowable flaw depths exceed the maximum flaw depth after 80 years of fatigue crack growth, underclad cracks of any shape are acceptable for service for 80 years, regardless of the size or orientation of the flaws.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

Based on the above information, the analysis associated with reactor vessel underclad crack growth has been projected to the end of the SPEO.

4.3.5 Reactor Coolant Pump Flywheel

TLAA Description

During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions which may result in overspeed of the reactor coolant pump increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway. An evaluation of the probability of failure over the current period of extended operation was performed. It demonstrated that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life.

The analysis associated with the reactor coolant pump flywheel was evaluated to consider EPU conditions (Reference 4.3.6.2). The results of this evaluation demonstrated that the original conclusions reached for license renewal remain valid with the implementation of the EPU. As a result, the analysis associated with the reactor coolant pump flywheel is valid with the implementation of the EPU through the current period of extended operation.

Considering the RCP flywheel probability of failure is part of the current licensing basis and is used to support safety determinations, and the probability of failure was based upon 60-year assumptions, this fatigue analysis has been identified as a TLAA requiring evaluation for the SPEO.

TLAA Evaluation

The PTN Westinghouse RCP motor flywheels consist of two large steel discs that are shrunk fit directly to the RCP motor shaft. The individual flywheel discs are bolted together to form an integral flywheel assembly, which is located above the RCP rotor core. Each flywheel disc is keyed to the motor shaft by means of three vertical keyways, positioned at 120° intervals. The bottom disc usually has a circumferential notch along the outside diameter bottom surface for placement of anti-rotation pawls.

Westinghouse manufactured the RCP motors for PTN. The RCP motor flywheels are made of SA-533 Grade B Class 1 steel. The ordering specifications for the Westinghouse flywheel materials (the first specification is dated December 1969) required that the RT_{NDT} from both longitudinal and transverse Charpy specimens be less than 10°F. Even though it is likely that the flywheels in operation have an RT_{NDT} of 10°F or less, a range of RT_{NDT} values from 0°F to 60°F was assumed in the integrity evaluations.

The pertinent flywheel parameters for PTN are provided below. Note that for the evaluations performed, the larger flywheel outside diameter for a particular flywheel assembly was used, since this was determined to be conservative with respect to stress and fracture. This larger dimension is noted below.

Outer diameter (inch) = 72
Bore (inch) = 8.375
Keyway radial length (inch) = 0.906
Pump and motor inertia (lbm-ft^2) = 70,000

Inspections

The PTN flywheels are inspected at the plant or during motor refurbishment. Inspections are conducted under the ASME Boiler and Pressure Vessel Code, Section XI standard practice for control of instrumentation and personnel qualification. Ultrasonic test (UT) level II and III examiners conduct the inspections.

WCAP-15666-A, which is included in PWR Owners Group, PWROG-17031-NP (Reference 4.3.6.18), a copy of which is included in Enclosure 4, discusses the examination volume, approach, access and exposure in detail. This discussion remains applicable for the SPEO.

WCAP-15666-A presents the results of a survey of historical plant ISI findings from owners' group member utilities, including Babcock and Wilcox (B&W) plants. The flywheel population surveyed was a total of 214. A total of 729 examination findings were reported, and no indications that would affect the integrity of the flywheels were found. A number of indications in the form of nicks and gashes were found in the keyway area, having been created by the act of removing or reassembling the flywheel. These were dispositioned as not affecting flywheel integrity, but are clear evidence that the act of disassembly and reassembly for refurbishment and inspection can produce damage.

The PTN operating experience noted in WCAP-15666-A identified that 36 inspections had been performed on 7 flywheels, with 34 of the inspections with no recordable indications. The two inspections with recordable indications were as follows:

(1) In 1974, laminations mid-wall (UT) in motor 1S-76P499 flywheel accepted as-is.

(2) In 1993, torn metal in keyway (PT) on motor 2S-76P499 flywheel removed by buffing.

In 2017, AREVA performed a study of refurbished Westinghouse RCP motors and documented the results of flywheel NDE testing. The method used for verifying findings was review of historical data packages, NDE data sheets, and/or Incoming/Final Refurbishment Reports. Ultimately, there were four flywheels with recordable indications discovered, all of which were deemed to be nonrelevant; no repairs were required on any flywheels with recordable indications. PTN had one flywheel inspection in the study, with no recordable indications.

Stress and Fracture Evaluation

WCAP-15666-A summarized the detailed stress and fracture evaluation. The ductile and brittle failure mechanisms were considered in the flywheel evaluation. For the evaluation, the flywheel failure speed was calculated for a range of postulated crack depths. Note that the brittle failure limit governs for large flaws. The limiting speed increases for small flaws. Using brittle fracture considerations alone, the limiting speed would approach infinity for vanishingly small flaws. The ductile failure limit governs for these situations. The evaluation requirements are per RG 1.14 (Reference 4.3.6.30).

Stresses in the flywheel are a strong function of the outer diameter. Therefore, the largest flywheel outer diameters for all Westinghouse RCP motors were selected to be bounding for the deterministic and probabilistic evaluations.

Table 4.3.5-1
RCP Flywheel Dimensions

Group	Outer Diameter (inch)	Bore (inch)	Keyway Radial Length (inch)	Comments
1	76.50	9.375	0.937	Maximum OD.
2	75.75	8.375	0.906	Large OD, minimum bore.

Ductile Failure Analysis

The flywheel stresses are dependent on dimensions and rotation speed. Extending the operating period another 20 years to 80 years does not affect the stress calculation. Therefore, the ductile failure analysis in performed in WCAP-15666-A remains valid for the SPEO.

Non-Ductile Failure Analysis

The flywheel stress intensity factor is dependent on geometry, postulated flaw dimensions and stress condition (due to rotational speed). Extending the operating period to 80 years does not affect the stress intensity factor calculations. Furthermore, the flywheel is remote from the reactor core and the effect of irradiation embrittlement is negligible. The fracture toughness would not change due to the 20 year extension, unlike the reactor vessel. Therefore, the non-ductile failure analysis in WCAP-15666-A remains valid for the SPEO.

Fatigue Crack Growth

Fatigue crack growth (FCG) is dependent on the flywheel stress intensity factor at operating and rest states and the number of start and stop cycles. As discussed previously, the 20 year extension to 80 years of operation has no impact on the stress intensity factor calculations.

Additionally, the 6000 start and stop cycles used in the FCG calculation of WCAP-15666-A remains bounding and applicable for PTN for the SPEO.

Excessive Deformation Analysis

The deformation of the flywheel is only dependent on the rotational speed and physical attributes of the flywheel. The 80-year extension has no impact on the excessive deformation analysis of the flywheel. The results in WCAP-15666-A remain applicable for the SPEO.

Summary of Stress and Fracture Results

The deterministic integrity evaluations in WCAP-15666-A remain applicable for another 20 years, to 80 years of operation. The RCP motor flywheels have a very high tolerance for the presence of flaws, especially with the 1500 rpm overspeed due to the application of LBB. As noted in WCAP-15666-A, the probabilistic assessment evaluates all credible flywheel speeds. There are no significant mechanisms for inservice degradation of the flywheels, since they are isolated from the primary coolant environment. The evaluations presented above have shown there is no significant deformation of the flywheels, even at maximum overspeed conditions. FCG calculations have shown that even with a large assumed flaw, the crack growth for another 20 years, to 80 years of operation is negligible. Therefore, based on these deterministic evaluations, the flywheel inspections completed prior to service are sufficient to ensure their integrity during service. As discussed above, the most likely source of inservice degradation is damage to the keyway region that could occur during disassembly or reassembly for refurbishment and inspection.

An evaluation (Reference 4.3.6.18) of the probability of failure over the SPEO was performed. The evaluation demonstrates that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over an 80-year service life.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

Based on the above information, the RCP flywheel fatigue analysis remains valid for the SPEO.

4.3.6 References

4.3.6.1 Structural Integrity Associates Engineering Report No. 1700109.402P, Revision 4 – REDACTED, “Evaluation of Fatigue of ASME Section III, Class 1 Components for Turkey Point Units 3 and 4 for Subsequent License Renewal”, March 2018 (Enclosure 4, Attachment 4).

4.3.6.2 FPL Letter No. L-2010-113 from Michael Kiley to U.S. Nuclear Regulatory Commission, "Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, License Amendment Request for Extended Power Uprate (LAR 205)," October 21, 2010, (ML103560169).

4.3.6.3 EPRI Report TR-104534, Volume 1, 2 &3, “Fatigue Management Handbook”, Research Project 3321, Rev. 1, December 1994.

4.3.6.4 NUREG-2192, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants.

4.3.6.5 Generic Safety Issue 190, “Fatigue Evaluation of Metal Components for 60-Year Plant Life,” U. S. Nuclear Regulatory Commission (ML020740117).

4.3.6.6 Memorandum, Ashok C. Thadani, Director, Office of Nuclear Regulatory Research, to William D. Travers, Executive Director of Operations – “Closeout of Generic Safety Issue 190, Fatigue Evaluation of Metal Components for 60 Year Plant Life,” U. S. Nuclear Regulatory Commission, December 26, 1999 (ML12338A526).

4.3.6.7 NUREG/CR-6260 (INEL 95/0045), Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components, February 1995.

4.3.6.8 Structural Integrity Associates Engineering Report No. 1700109.401P, Revision 5 – REDACTED, “Evaluation of Environmentally-Assisted Fatigue for Turkey Point Units 3 and 4 for Subsequent License Renewal”, April 2018 (Enclosure 4, Attachment 5).

4.3.6.9 NUREG/CR-6583 (ANL-97/18), Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels, March 1998.

4.3.6.10 NUREG/CR-5704 (ANL-98/31), Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels, April 1999.

4.3.6.11 NUREG/CR-6909 (ANL-06/08), Revision 1, Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, March 2014.

4.3.6.12 Structural Integrity Associates Engineering Report No. 1100756.401, Revision 1, “Flaw Tolerance Evaluation of Turkey Point Surge Line Welds Using ASME Code Section XI, Appendix L,” May 2012.

4.3.6.13 FPL Letter No. L-2012-214 from Michael Kiley to U.S. Nuclear Regulatory Commission, “Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, License Renewal Commitment, Submittal of Pressurizer Surge Line Welds Inspection Program,” May 16, 2012, ADAMS Accession No. ML12152A156.

4.3.6.14 Letter from Farideh E. Saba, Senior Project Manager (NRC) to Mr. Mano Nazar (NextEra Energy), “Turkey Point Nuclear Generating Units 3 and 4 - Review of License Renewal Commitment for Pressurizer Surge Line Welds Inspection Program (TAC Nos. ME8717 and ME8718),” U.S. Nuclear Regulatory Commission, Washington, DC, May 29, 2013, ADAMS Accession No. ML13141A595.

4.3.6.15 Westinghouse Report, WCAP-15338-A, Rev. 0, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants,” October 2002.

4.3.6.16 PWR Owners Group, PWROG-17031-NP, Rev. 0, “Update for Subsequent License Renewal: WCAP-15338-A, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants,” August 2017 (Enclosure 4, Attachment 9).

4.3.6.17 EPRI 1024995, “EAF Screening, Process and Technical Bases for Identifying EAF Limiting Locations”, August 2012.

4.3.6.18 PWR Owners Group, PWROG-17011-NP, Rev. 0, “Update for Subsequent License Renewal: WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination” and WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination”, November 2017 (Enclosure 4, Attachment 10).

4.3.6.19 Westinghouse LTR-SDA-II-17-13-P/NP, Revision 2, Environmentally Assisted Fatigue Evaluation of the Turkey Point Unit 3 and Unit 4 Pressurizer Upper Head and Shell and Reactor Vessel Core Support Blocks, November 30, 2017 (Enclosure 4, Attachment 7).

4.3.6.20 Westinghouse LTR-CECO-II-17-025-P/NP, Revision 1, Environmentally Assisted Fatigue Evaluation of the Turkey Point Unit 3 and Unit 4 Replacement Steam Generators, November 30, 2017 (Enclosure 4, Attachment 7).

4.3.6.21 AREVA Calculation No. 32-9280707, Rev. 0, Turkey Point -3 & 4 CRDM Nozzle to Adapter Weld Connection EAF Evaluation, December 15, 2017 (Enclosure 4, Attachment 8).

4.3.6.22 AREVA Calculation No. 32-9280708, Rev. 0, Turkey Point 3 & 4 Replacement RVCH J Groove, December 12, 2017 (Enclosure 4, Attachment 8).

4.3.6.23 AREVA Calculation No.32-9280709, Rev. 0, 12/15/17, TP CRDM Latch Housing Environmentally Assisted Fatigue, December 15, 2017 (Enclosure 4, Attachment 8).

4.3.6.24 AREVA Calculation No. 32-9280710, Rev. 0, TP Vent Nozzle Environmentally Assisted Fatigue, December 14, 2017 (Enclosure 4, Attachment 8).

4.3.6.25 AREVA Calculation No. 32-9280711, Rev. 0, Turkey Point SLR EAF Analysis for Reactor Vessel Flange, December 14, 2017 (Enclosure 4, Attachment 8).

4.3.6.26 AREVA Calculation No. 32-9280712, Rev. 0, TP CRDM Lower Joint Environmentally Assisted Fatigue, December 15, 2017 (Enclosure 4, Attachment 8).

4.3.6.27 AREVA Letter No. AREVA-17-02742, Final CUF_{EN} Results –Turkey Point 3 & 4 – SLR EAF Analyses, December 6, 2017 (Enclosure 4, Attachment 8).

4.3.6.28 Pressurizer Lower Head Structural Integrity Associates EAF Calculations 1700804.318 Revision 0, 1700804.317 Revision 0, 1700804.316P Revision 0 – REDACTED (Enclosure 4, Attachment 6).

4.3.6.29 Pressurizer Spray Nozzle Structural Integrity Associates EAF Calculations 1700804.315P Revision 2 – REDACTED, 1700804.314P Revision 1 – REDACTED, 1700804.313P Revision 2 – REDACTED (Enclosure 4, Attachment 6).

4.3.6.30 United States Nuclear Regulatory Commission, Office of Standards Development, Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity," Revision 1, August 1975.

4.3.6.31 NUREG/CR-6909 (ANL-06/08), Revision 0, Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, February 2007.

4.4 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL EQUIPMENT

TLAA Description

Thermal, radiation, and cyclical aging analyses of plant electrical and instrumentation components, developed to meet 10 CFR 50.49 requirements, have been identified as TLAAs. The NRC has established environmental qualification (EQ) requirements in 10 CFR 50.49 and 10 CFR Part 50, Appendix A, Criterion 4. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in- service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a design basis accident such as a loss-of-coolant accident (LOCA), high energy line break (HELB), or main steam line break (MSLB).
10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations for electrical components in the EQ Program that involve time-limited assumptions defined by the current operating term of 60 years have been identified as TLAAs for SLR because the criteria contained in 10 CFR 54.3 are met. Aging evaluations that qualify components for shorter periods, and that therefore require refurbishment, replacement, or extension of their qualified life, are not TLAAs.

TLAA Evaluation

The PTN Environmental Qualification of Electric Equipment AMP described in Section B.2.2.4 meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of components within the scope of the Environmental Qualification of Electric Equipment AMP, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected during their service life.

10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability.
10 CFR 50.49(e)(5) also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions. 10 CFR 50.49(k) permits different qualification criteria to apply based on plant and component vintage and 10 CFR 50.49(l) requires replacement equipment to be qualified in accordance with the provisions of 10 CFR 50.49. Supplemental environmental qualification regulatory guidance for compliance with these different qualification criteria is provided in the DOR Guidelines, “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors” (Reference 4.4.1.1), NUREG-0588, Revision 1, “Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment” (Reference 4.4.1.2), and Regulatory Guide 1.89, Revision 1, “Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants” (Reference 4.4.1.3).

Compliance with 10 CFR 50.49 provides reasonable assurance that the component can perform its intended functions during accident conditions after experiencing the effects of in- service aging. The Environmental Qualification of Electric Equipment AMP manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

The Environmental Qualification of Electric Equipment AMP, which implements the requirements of 10 CFR 50.49, as further defined and clarified by NUREG-0588 and Regulatory Guide 1.89 is viewed as an aging management program for SLR under 10 CFR 54.21(c)(1)(iii). Reanalysis of an aging evaluation to extend the qualifications of components is performed on a routine basis as part of the Environmental Qualification of Electric Equipment AMP. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The disposition of the TLAAs in accordance with 10 CFR 54.21(c)(1)(iii), which states that the effects of aging will be adequately managed for the SPEO, is chosen based on the fact the Environmental Qualification of Electric Equipment Program will manage the aging effects of the electrical and instrumentation components associated with the EQ TLAAs.

NUREG-2192 states that the staff evaluated the Environmental Qualification of Electric Equipment program (10 CFR 50.49) and determined that it is an acceptable aging management program to address environmental qualification according to 10 CFR 54.21(c)(1)(iii). The evaluation referred to in NUREG-2192 contains sections on “EQ Component Reanalysis Attributes, Evaluation, and Technical Basis” is the basis of the description provided below.

Component Reanalysis Attributes

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing conservatism 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 AMP. While a component life-limiting condition may be due to thermal, radiation, or cyclical aging, the majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, 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 quality assurance program requirements, which require the verification of assumptions and conclusions. As previously noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods

Thermal Considerations - The component qualification temperatures were calculated for 80 years using the Arrhenius method, as described in EPRI NP-1558, “A Review of Equipment Aging Theory and Technology” (Reference 4.4.1.4). As thermal aging is governed by the ambient temperature to which the device is exposed, the Environmental Qualification of Electric Equipment AMP conservatively assumes a continuous ambient temperature of 122°F (50°C) for inside containment installations, and a continuous ambient temperature of 104°F (40°C) for outside containment installations.

For additional conservatism, a temperature rise of 10°C is added to these assumed operating temperatures for continuous duty power cables to account for ohmic heating.

The component's qualification thermal aging test temperature and duration is compared to the new required service conditions. If the equivalent (as determined by the Arrhenius methodology) qualification testing conditions exceed the required service conditions, then no additional evaluation was required.

In connection with plant modifications, some new environmentally qualified components that will not experience 80 years of thermal aging by the end of the SPEO were installed at PTN. In these cases, credit may be taken for less than 80 years of aging.

Radiation Considerations - The PTN Environmental Qualification of Electric Equipment AMP has established bounding radiation dose qualification values for all EQ components. These bounding radiation dose values were determined by component vendors through testing.

The worst case total integrated radiation dose received by equipment located outside containment during 80 years of normal operation is governed by the location of the device with respect to radiation sources (recirculating piping and heat exchangers). These radiation doses were calculated based on the normal operating radiation dose which conservatively considers operation with 1 percent failed fuel. In almost all cases, the dose received is limited to gamma radiation since beta radiation does not represent a significant contribution during normal operation. A few cases inside containment included the impacts of neutron radiation.

Due to EPU, which was implemented in 2012 to 2013 for both units, the core power level increased from 2300 MWt to 2644 MWt. Consequently, normal operation gamma dose rates would be anticipated to increase by 2644/2300 = 1.150 (for EQ purposes, the increase is conservatively rounded to 16%). Since Unit 3 went on line in December 1972 and Unit 4 in September 1973, the 80-year normal operation doses are conservatively estimated reflecting 38 years at the pre EPU dose rate and 42 years at the uprated power level for both units. A 10% factor is included for the survey dose rates in order to account for possible measurement uncertainty.

To verify that the bounding radiation values are acceptable for the SPEO, 80-year integrated dose values were determined and then the established accident dose to the 80-year normal operating dose for the component to determine the 80 year total integrated dose (TID). This was then compared to the qualification value established by the current qualification. If the qualification value exceeded the 80 year TID, then no additional evaluation was required.

Wear Cycle Considerations - The wear cycle aging effect is only applicable to active components, such as but not limited to, solenoid valves, motor-operated valves, transmitters, and connectors that are periodically disconnected. Established wear cycle limits were compared to the projected wear cycles for 80 years to establish acceptability for the SPEO.

Data Collection and Reduction Methods

The primary method used for a reanalysis per the Environmental Qualification of Electric Equipment AMP is reduction of conservatism in the component service conditions used in the prior aging evaluation, including temperature, radiation, and cycles. Temperature data used in an aging evaluation is conservative and 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 were justified. Similar methods of reducing conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions

The Environmental Qualification of Electric Equipment AMP component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. 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

Per the Environmental Qualification of Electric Equipment AMP, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component is refurbished, replaced, or re-qualified 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 re-qualify the component if the reanalysis is unsuccessful. For EQ equipment with a qualified life less than the required design life of the plant, “ongoing qualification” is a method of long-term qualification involving additional testing. Ongoing qualification or retesting, as described in IEEE Standard 323-1974, Section 6.6, “Ongoing Qualification,” paragraphs (1) and (2), is not currently considered a viable option and PTN has no plans to implement it. If this option becomes viable in the future, ongoing qualification or retesting will be performed in accordance with accepted industry and regulatory standards.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on the intended function(s) will be adequately managed for the SPEO. The Environmental Qualification of Electric Equipment AMP has been demonstrated to be capable of programmatically managing the qualified lives of the electrical and instrumentation components falling within the scope of the program for license renewal. The continued implementation of the Environmental Qualification of Electric Equipment AMP provides reasonable assurance that the aging effects will be managed and that EQ components will continue to perform their intended functions for the SPEO. This result meets the requirements of 10 CFR 54.21(c)(1)(iii).

4.4.1 References

4.4.1.1 DOR Guidelines, “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors,” U. S. Nuclear Regulatory Commission, June 1979.

4.4.1.2 NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment,” U. S. Nuclear Regulatory Commission, July 1981.

4.4.1.3 Regulatory Guide 1.89, Revision 1, “Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants,” U. S. Nuclear Regulatory Commission, June 1984.

4.4.1.4 EPRI NP-1558, “A Review of Equipment Aging Theory and Technology,” Electric Power Research Institute, September 1980.

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS

TLAA Description

The Turkey Point Units 3 and 4 containment buildings are post-tensioned, reinforced concrete structures composed of vertical cylinder walls and a shallow dome, supported on a conventional reinforced concrete base slab. The cylinder walls are provided with vertical tendons and horizontal hoop tendons. The dome is provided with three groups of tendons oriented 120-degrees apart.

Over time, the containment prestressing forces decrease due to relaxation of the steel tendons and due to creep and shrinkage of the concrete. The containment tendon prestressing forces were calculated during the original design considering the magnitude of the tendon relaxation and concrete creep and shrinkage over the 40-year life of the plant. The Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3) and ASME Section XI, Subsection IWL AMP (Section B.2.3.31) perform periodic surveillances of individual tendon prestressing values. Predicted lower limit (PLL) force values are calculated for each tendon prior to the surveillances to estimate the magnitude of the tendon relaxation and concrete creep and shrinkage for the given surveillance period. The prestressing forces are measured and plotted, and trend lines are developed, to ensure the average tendon group prestressing values remain above the respective minimum required values (MRVs) until the next scheduled surveillance. The predicted lower limit force values and regression analyses, utilizing actual measured tendon forces, are used to evaluate the acceptability of the containment structure to perform its intended function over the current 60-year life of the plant, and therefore, are TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

The prestress of containment tendons decreases over time as a result of seating of anchorage losses, elastic shortening of concrete, creep of concrete, shrinkage of concrete, relaxation of prestressing steel, and friction losses. At the time of initial licensing, the magnitude of the prestress losses throughout the life of the plant was predicted and the estimated final effective preload at the end of 40 years was calculated for each tendon type. The final effective preload was then compared with the minimum required preload to confirm the adequacy of the design. The estimated final effective prestressing force at the end of plant life was projected to 60 years during the original license renewal process. Described below is the summary of the evaluation for 80 years.

<u>Predicted Lower Limit (PLL)</u>

The containment tendon prestressing force values were calculated during the original design of the containment structure to determine the initial prestressing force required for each tendon group such that the prestressing force would remain above the respective MRVs over the 40-year life of the plant. The initial tendon prestressing force was calculated for each tendon type to compensate for the steel tendon relaxation losses and concrete creep and shrinkage so that the estimated final effective tendon prestressing force at the end of the 40 years would be higher than the minimum required values (MRVs). The estimated final effective prestressing force was extended to 60 years during the original license renewal process. As part of the ASME Section XI, Subsection IWL AMP (Section B.2.3.31) inspections related to tendon examinations, PLL force values are calculated for each individual tendon scheduled for examination, for the given surveillance year. The PLL force values are developed consistent with the guidance presented in Regulatory Guide 1.35.1 (Reference 4.5.1.1). Actual measured values for each tendon are compared to their respective PLL values, with acceptance criteria consistent with ASME Section XI, Subsection IWL requirements.

Regression Analysis

A regression analysis is developed for each of the three tendon groups to determine the trend over time in prestressing values of individual tendons within each tendon group. The regression analysis consists of a trend line utilizing actual individual tendon prestressing forces measured during successive ASME Section XI, Subsection IWL surveillances, consistent with NRC Information Notice 99-10, Attachment 3 (Reference 4.5.1.2). The trend lines are periodically updated with new tendon prestressing force data following each surveillance. The trend lines are used to demonstrate that the average group prestressing forces will remain above the group MRV until the next scheduled surveillance, and potentially for the life of the plant.

Assessment

The regression analyses associated with the tendons have been reanalyzed to extend the trend lines from 60 years to 80 years. The extended trend lines have been calculated using individual tendon prestressing force values based on data incorporating the latest surveillances for Turkey Point Units 3 and 4 in 2017. In all cases, the regression analyses predict the prestressing forces will remain above the respective group MRVs through the SPEO.

Figures 4.5-1 through 4.5-6 contain the reanalyzed regression analyses for each tendon group at PTN. Extended trend lines have been developed for both the group control tendons, as well as for all tendons within the respective group, including the control tendons, and plotted with the MRVs over the 80 year period.

The Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3) will monitor and manage the TLAA and the associated loss of tendon prestressing forces during the SPEO. The regression analyses are periodically updated following successive surveillances to ensure that estimated values remain above the MRVs until the next scheduled surveillance, and potentially for the life of the plant. Individual measured tendon prestressing forces will be compared to predicted PLL values and trend lines developed for the SPEO.

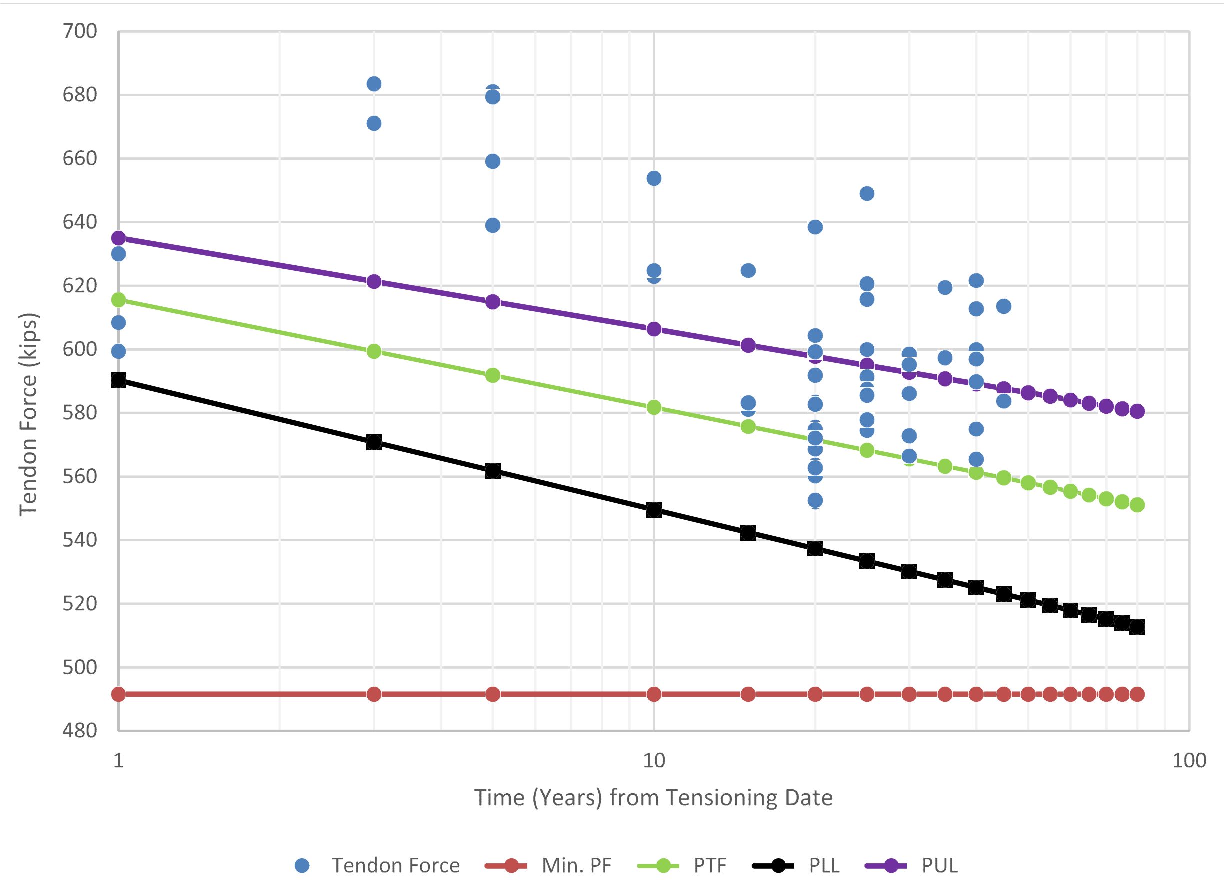
New upper limit curves, lower limit curves, and trend lines of measured prestressing forces have been established for all tendons through the SPEO as part of the Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3). The predicted final effective preload at the end of 80 years exceeds the minimum required preload for all containment tendons.

Consequently, the post-tensioning system will continue to perform its intended function throughout the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The concrete containment tendon prestress analysis has been projected to the end of the SPEO. Additionally, the Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3) and ASME Section XI, Subsection IWL AMP (Section B.2.3.31) will manage the effects of aging related to prestress forces on the containment tendon prestressing system so that the intended function will be adequately managed for the SPEO.

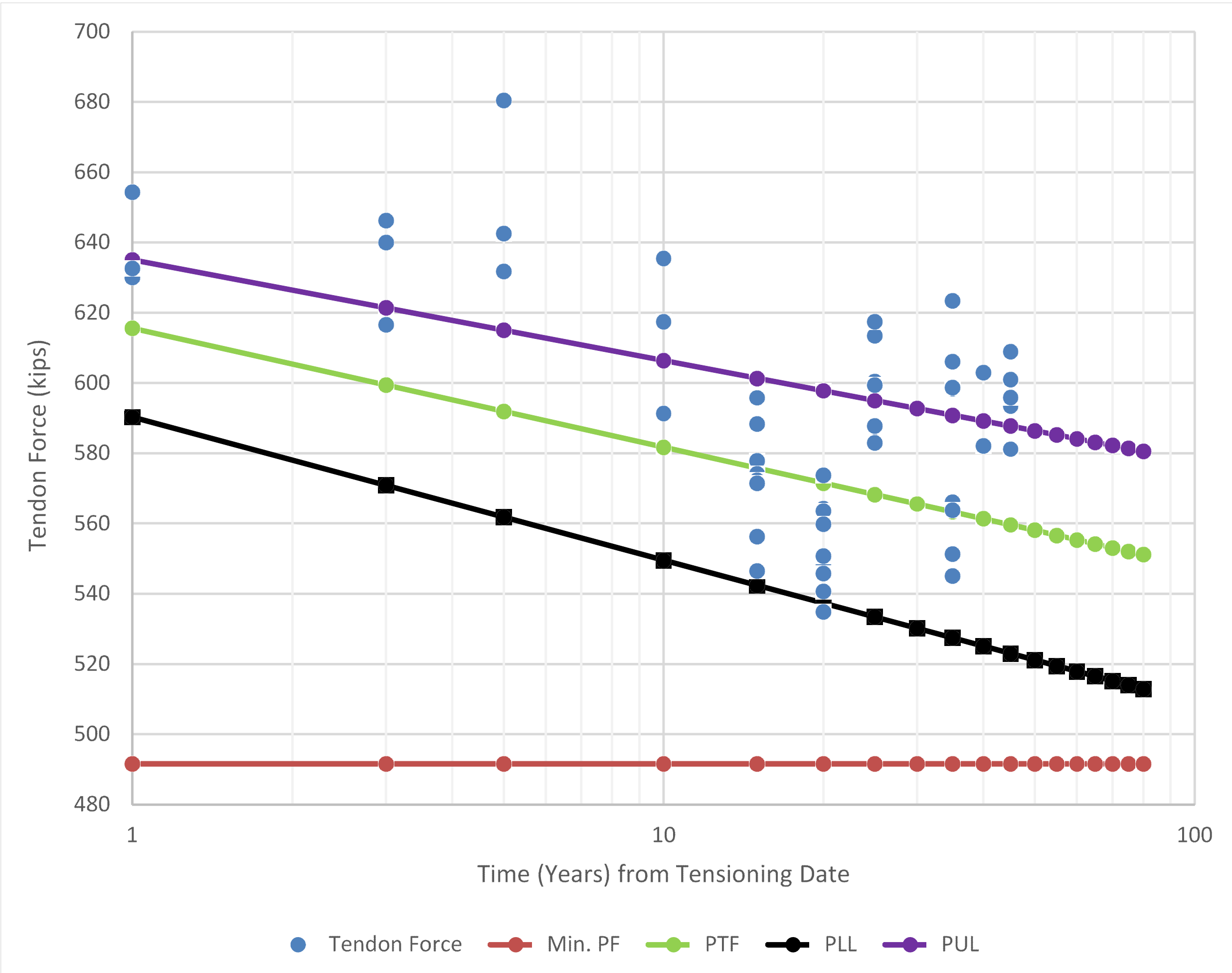
Figure 4.5-1
Unit 3 Hoop Tendons
1st Through 45th Year Tendon Surveillance



Notes:

1. Min. PF = Minimum prestressing force
2. PTF = Predicted tendon force
3. PLL = Predicted lower limit
4. PUL = Predicted upper limit

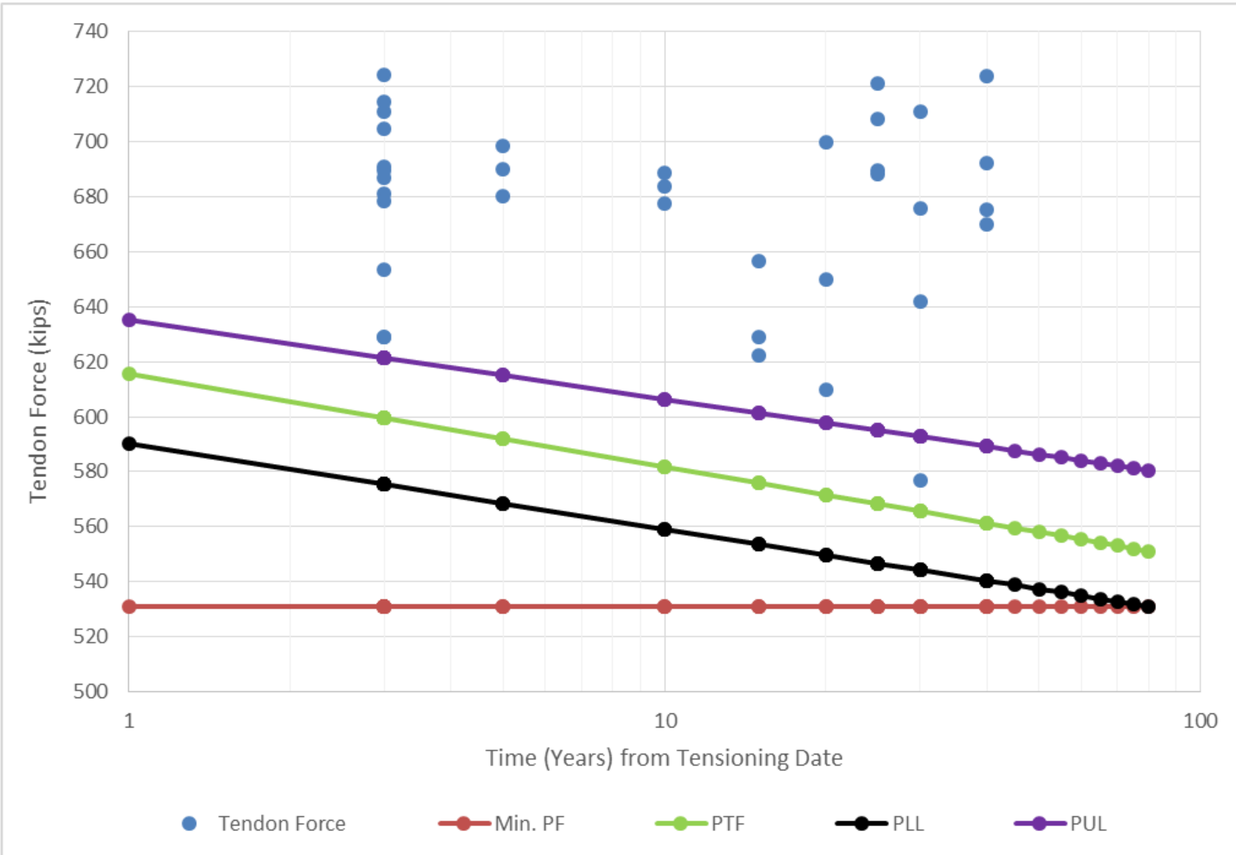
Figure 4.5-2
Unit 4 Hoop Tendons
1st Through 45th Year Tendon Surveillance



Notes:

1. Min. PF = Minimum prestressing force
2. PTF = Predicted tendon force
3. PLL = Predicted lower limit
4. PUL = Predicted upper limit

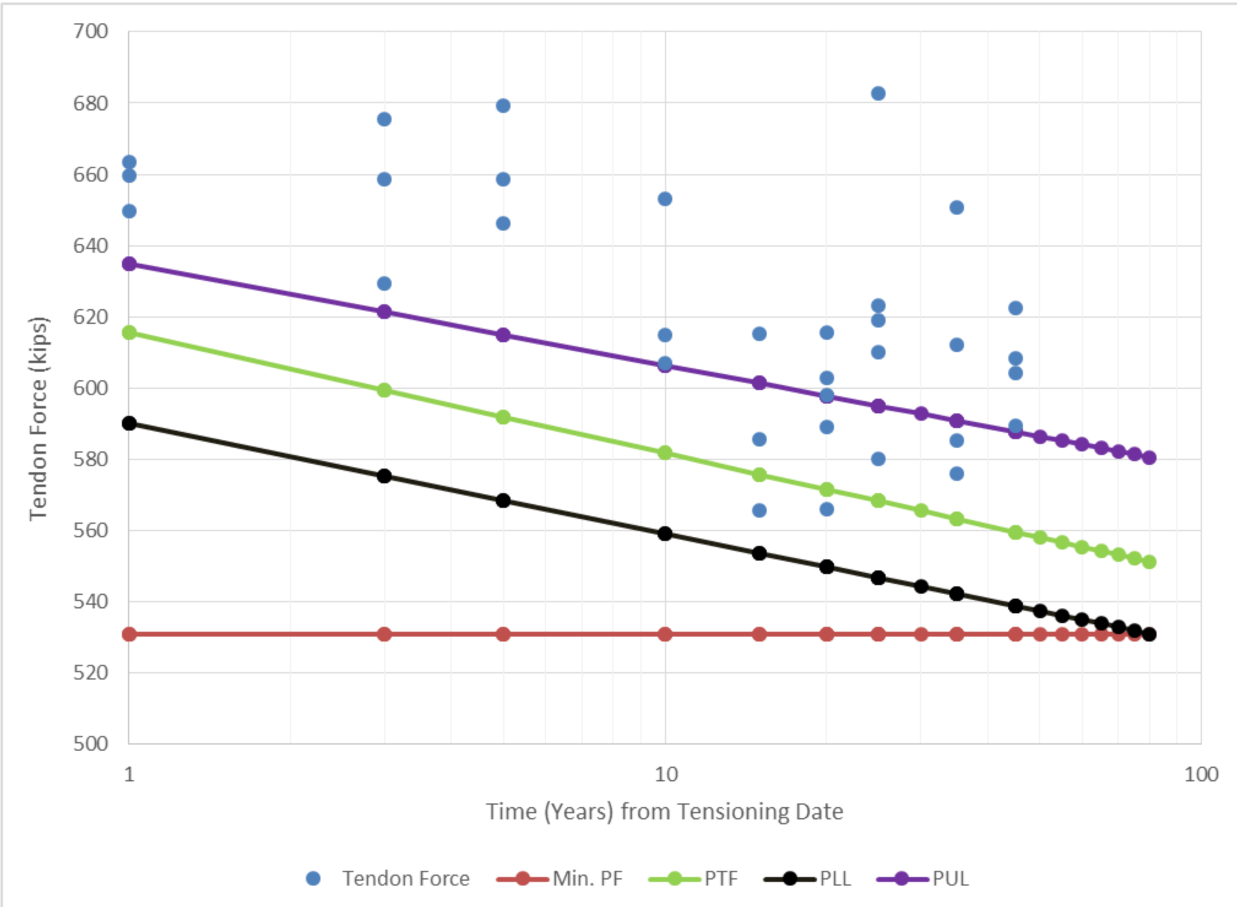
Figure 4.5-3
Unit 3 Dome Tendons
3rd Through 45th Year Tendon Surveillance



<u>Notes:</u>

1. Min. PF = Minimum prestressing force
2. PTF = Predicted tendon force
3. PLL = Predicted lower limit
4. PUL = Predicted upper limit

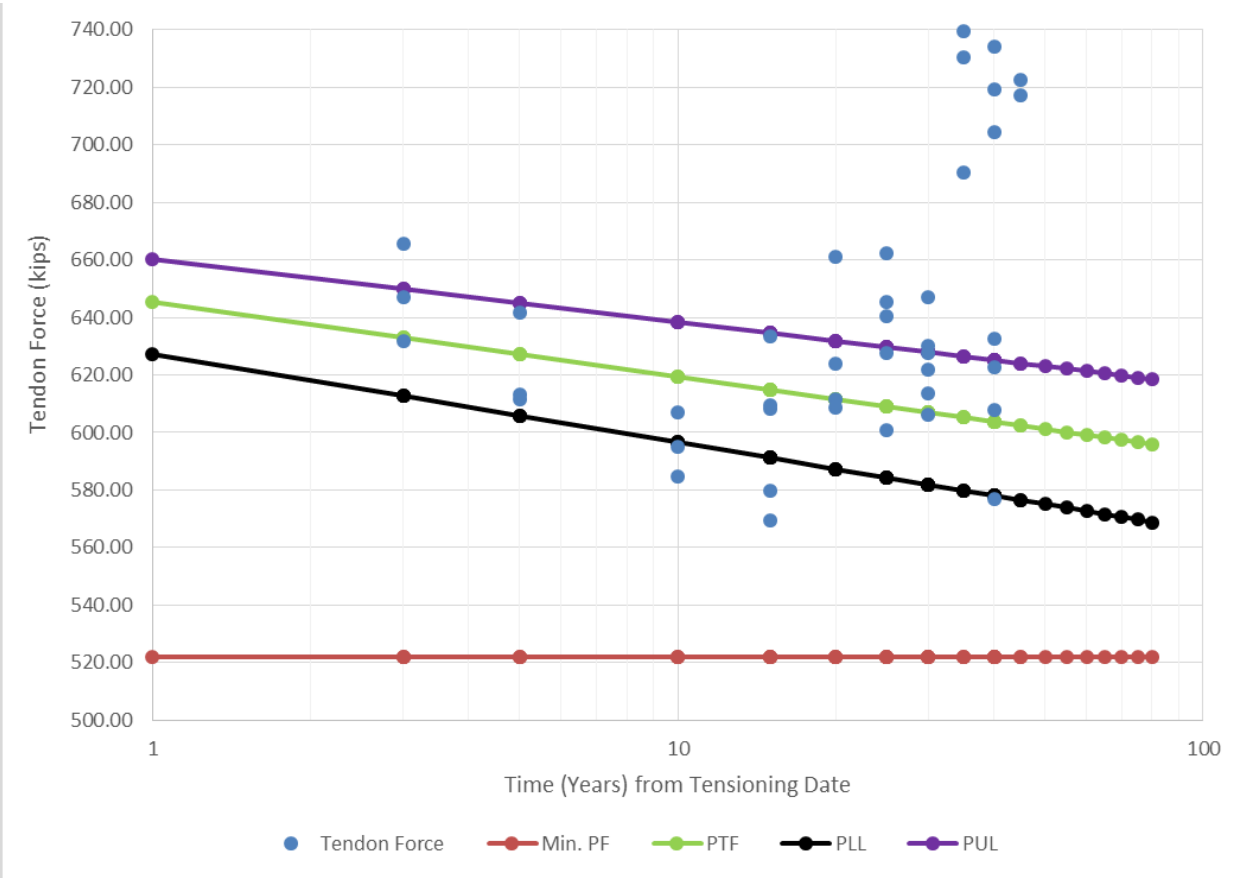
Figure 4.5-4
Unit 4 Dome Tendons
1st Through 45th Year Tendon Surveillance



Notes:

1. Min. PF = Minimum prestressing force
2. PTF = Predicted tendon force
3. PLL = Predicted lower limit
4. PUL = Predicted upper limit

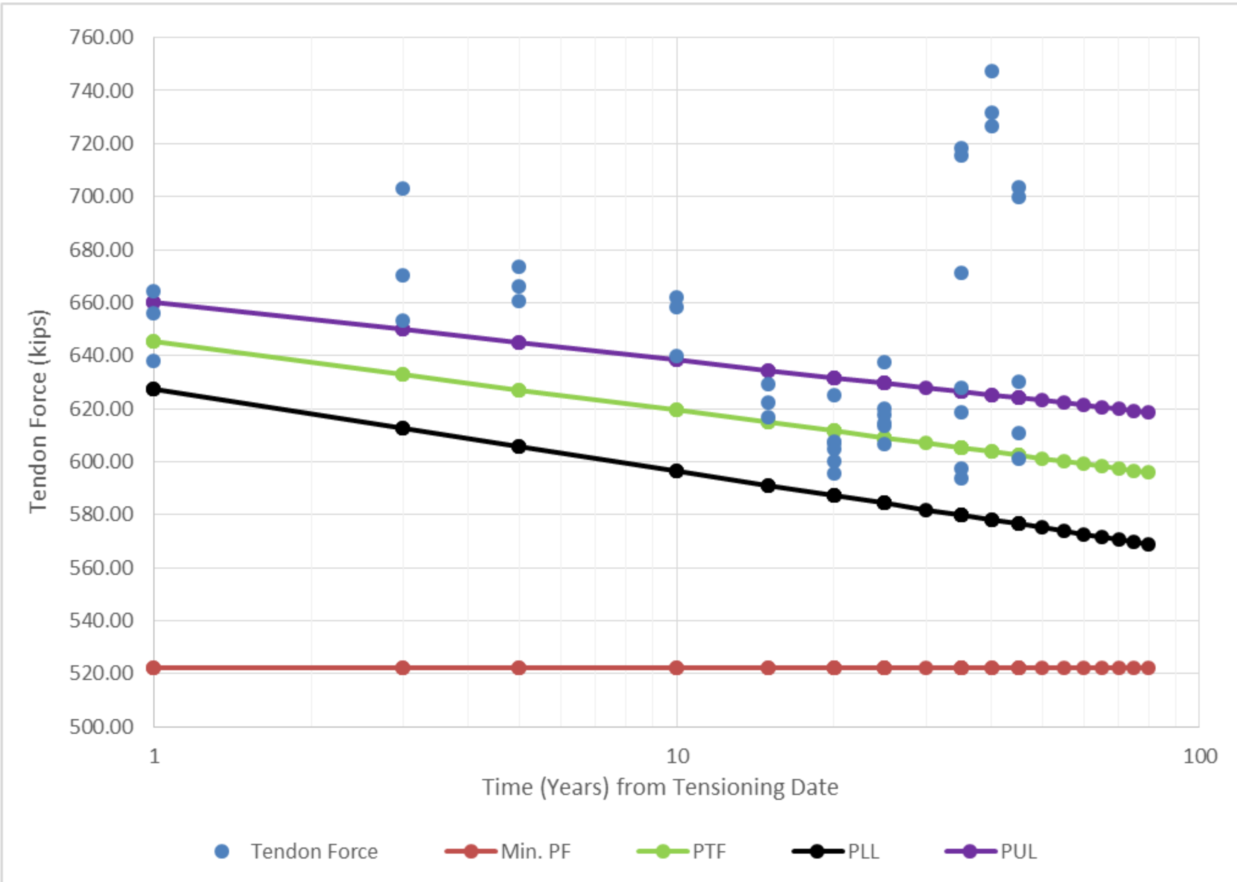
Figure 4.5-5
Unit 3 Vertical Tendons
3rd Through 45th Year Tendon Surveillance



Notes:

1. Min. PF = Minimum prestressing force
2. PTF = Predicted tendon force
3. PLL = Predicted lower limit
4. PUL = Predicted upper limit

Figure 4.5-6
Unit 4 Vertical Tendons
1st Through 45th Year Tendon Surveillance



Notes:

1. Min. PF = Minimum prestressing force
2. PTF = Predicted tendon force
3. PLL = Predicted lower limit
4. PUL = Predicted upper limit

4.5.1 References

4.5.1.1 Regulatory Guide 1.35.1, Determining Prestressing Forces for Inspection of Prestressed Concrete Containments Revision, July 1990.

4.5.1.2 NRC Information Notice 99-10, Rev. 1, “Degradation of Prestressing Tendon Systems In Prestressed Concrete Containments,” Attachment 3, October 1999.

4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE

TLAA Description

Each PTN containment structure includes a liner attached to the entire inside surface that provides a leak-tight membrane. The original PTN containment design specification requires the liner to be analyzed for the effects of cyclic loading. Since the current design analysis for the containment liner is based upon 60-year design inputs including implementation of the EPU project, it has been identified as a TLAA requiring evaluation for the SPEO.

TLAA Evaluation

The interior surface of each containment is lined with welded steel plate to provide a leak-tight barrier. Design criteria are applied to the liner to assure that the specified allowed leak rate is not exceeded under design basis accident conditions. The following fatigue loads, as described in UFSAR Appendix 5B, Section B.2.1, were considered in the design of the liner plates and are considered TLAAs for SLR:

(1) Thermal cycling due to containment interior temperature varying during the heatup and cooldown of the reactor coolant system. The number of cycles considered in the design analysis for this loading is 500.

(2) Thermal cycling due to annual outdoor temperature variations. The number of projected cycles for this loading is 60 for the plant life of 60 years.

(3) Thermal cycling due to the maximum hypothetical accident is assumed to be one.

(4) Thermal load cycles in the piping system are isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Boiler and Pressure Vessel Code, Section III, fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the unit life.

Each of the above items has been evaluated for the SPEO.

For item 1, the 500 design thermal cycles were compared to the heatup and cooldown design cycles (transients) for the reactor coolant system. The reactor coolant system was designed to withstand 200 heatup and cooldown thermal cycles. The evaluation described in Section 4.3.1 determined that the originally projected number of maximum reactor coolant system design cycles is conservative and envelops the projected cycles for the SPEO. Therefore, the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is bounding for the SPEO.

For item 2, the number of thermal cycles due to annual outdoor temperature variations was increased from 60 to 80 to account for the SPEO. Considering the 500 thermal cycles discussed in item 1 includes a margin of 300 thermal cycles above the 200 reactor coolant system allowable design heatup and cooldown cycles, there is sufficient margin to accommodate the additional 20 cycles of annual outdoor temperature variation. In addition, the annual outdoor temperature variation is minor when compared to a heatup and cooldown thermal cycle. Therefore, this loading condition is considered acceptable for the SPEO as it is enveloped by item 1.

For item 3, the assumed value for thermal cycling due to the maximum hypothetical accident remains unchanged for SLR.

For item 4, the design of the containment piping penetrations has been reviewed and the design meets the general requirements of the 1965 Edition of ASME Boiler and Pressure Vessel Code, Section III. The main steam piping, feedwater piping, blowdown piping, and letdown piping are the only piping penetrating the containment wall and liner plate that contribute significant thermal loading on the liner plate. The projected number of actual operating cycles for these piping systems through 80 years of operation was determined to be less than the original design limits as demonstrated in Section 4.3.2.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The analyses associated with the containment liner plate and penetrations have been evaluated and determined to remain valid for the SPEO.

4.7 OTHER PLANT-SPECIFIC TLAAs

4.7.1 Bottom-Mounted Instrumentation Thimble Tube Wear

TLAA Description

As discussed in NRC Information Notice (IN) 87-44, Supplement 1, "Thimble Tube Thinning in Westinghouse Reactors" (Reference 4.7.7.1), thimble tubes have experienced thinning as a result of flow-induced vibration. Thimble tube wear results in degradation of the reactor coolant system pressure boundary and could potentially create a non-isolable leak of reactor coolant. Since flow induced vibration continues throughout the plant life, thimble tube wear is considered a TLAA.

TLAA Evaluation

Bottom-mounted instrumentation flux thimble tubing through wall wear caused by flow induced vibration was first reported by a licensee in 1981 in three thimble tubes. Subsequent inspections at other utilities identified additional worn flux thimble tubing, some with significant wall loss. In 1987 the NRC issued IN 87-44, "Thimble Tube Thinning in Westinghouse Reactors," with a supplement issued on March 28, 1988 (Reference 4.7.7.1). On July 26, 1988, the NRC issued Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors" (Reference 4.7.7.2). The purpose of this bulletin was to "request that addressees establish and implement an inspection program to periodically confirm incore neutron monitoring system thimble tube integrity."

As a result of the NRC bulletin, PTN performed eddy current testing (ECT) of the thimble tubes in both Units. Turkey Point Unit 3 tubing was tested in 1990 and 1992, and Unit 4 tubing was tested in 1988 and 1990. Based on these inspections, a plan for future inspections was established. Subsequently, the Flux Thimble Tube Inspection AMP (Section B.2.3.24) was implemented as part of the original license renewal effort.

The thimble tubing was again tested in October 2004 for Unit 3, and in April 2005 for Unit 4. The results of these examinations showed what appeared to be an increase in flow induced vibrational wear. See the operating experience discussion in Section B.2.3.24 for further details. The PTN Flux Thimble Tube Inspection AMP described in Section B.2.3.24 provides the methodology for analytical evaluation, inservice inspection, and repair or replacement of the flux thimble tubing that is susceptible to wall thinning (wear) as a result of flow induced vibration. The basic examination schedule (interval) of every two to three refueling cycles was developed by Westinghouse based on evaluation of results obtained from the 2004 and 2005 refueling outages.

Future examination intervals should be determined based on disposition of examination results and engineering evaluations that have been completed as required to substantiate the decision for an alternate examination interval.

Reduced scope examinations (of selected worst case tubes) may be warranted if growth rate assessments determine that wear will not progress beyond expected levels.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The PTN Flux Thimble Tube Inspection program (Section B.2.3.24) effectively manages the aging effects of material loss due to fretting wear for the SPEO.

4.7.2 Emergency Containment Cooler Tube Wear

TLAA Description

The component cooling water (CCW) flow rate through the emergency containment cooling (ECC) coolers could exceed the nominal design flow during monthly operability testing. Flow rates as high as 5500 gpm have been experienced during surveillance testing. High flow rates can produce increased wear on the inside surface of the (ECC) cooler coils. The (CCW) flow rate through the (ECC) coolers could also exceed the nominal design flow of 2000 gpm during the injection phase of a LOCA or during the monthly operability test.

This high flow rate can produce increased wear on the inside surface of the ECC coils. This increased erosion wear rate has been predicted to be up to 0.5 mils/year due to flow induced erosion with an additional impingement wear rate of 0.6 mils/year at those locations subject to impingement. This results in a wear rate in the range of 0.5 mils/year to 1.1 mils/year depending on coil's location. This effect was evaluated and the tube wall nominal thickness of 0.049" was projected not to decrease below the minimum ASME Section III, Class C required wall thickness of 0.011" during the current 60 year operating period. Since tube wear continues throughout the plant life, ECC cooler tube wear is considered a TLAA.

TLAA Evaluation

To ensure ECC cooler coil reliability, an inspection for minimum tube wall thickness was conducted in 2011 prior to the initial period of extended operation. The actual measured wall was 0.039". Therefore, based on an initial tube wall thickness of 0.049", the calculated wear rate is (0.049-0.039)/ 38 years = 0.000263 in/yr. The expected material loss is calculated by multiplying the erosion rate (0.000263 in/yr) by the remaining years of service from the one time inspection activity (4/04/2011) to the end of the SPEO (42 years). The expected material loss value is then added to the minimum allowable wall thickness value of 0.011 inches which includes a 10% margin typically used in wear applications. Based on the above, the acceptance criterion for SLR was determined to be 0.022 inches. The results concluded that the calculated tube wear rates would be acceptable for the SPEO. However, since tube wall loss has been observed, a one-time inspection to confirm the projected tube wear rates are acceptable for the SPEO will be performed.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The One-Time Inspection program described in Section B.2.3.20 will ensure that the aging effect of emergency containment cooler tube wear will be adequately managed for the SPEO.

4.7.3 Leak-Before-Break Analysis for Reactor Coolant System Piping

TLAA Description

Westinghouse performed a plant specific primary loop piping leak-before-break (LBB) analysis for Turkey Point Units 3 and 4 in 1994. The results of the analysis were documented in WCAP-14237 (Reference 4.7.7.3). The LBB analysis was performed to show that any potential leaks that develop in the reactor coolant system loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. The NRC reviewed WCAP-14237 and approved it for Turkey Point Units 3 and 4 in a letter dated June 23, 1995 (Reference 4.7.7.4). Subsequently, in 2000, the LBB analysis was updated to support Turkey Point Units 3 and 4 operation during the original PEO (60 year plant service) and documented in WCAP-15354 (Reference 4.7.7.5). Additionally, an evaluation of the effect of the EPU on the LBB results was performed in 2009 with acceptable results.

Considering the LBB postulated crack stability analysis is related to the period of plant operation, the LBB analysis is a TLAA.

TLAA Evaluation

In WCAP-15354, Revision 1 (Reference 4.7.7.6), copies of which are provided in Enclosure 4 (non-proprietary) and Enclosure 5 (proprietary), the LBB evaluations are performed for the SPEO (80 years of operation). The aging effects that must be addressed for SLR include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the reactor coolant system loop piping is embrittlement of the duplex ferritic cast austenitic stainless steel components.

Specifically, this evaluation demonstrated compliance with LBB technology for the reactor coolant system piping for 80 year plant service. WCAP-15354, Revision 1 (Reference 4.7.7.6) documents the plant specific geometry, loading, and material properties used in the fracture mechanics evaluation. The evaluation also examined potential material degradation due to thermal aging. While the Turkey Point Units 3 and 4 primary loop forged stainless steel piping (A376-TP316) does not degrade due to thermal aging, the primary loop cast austenitic stainless steel elbow fittings (A351-CF8M) are susceptible to thermal aging at reactor coolant system operating temperatures. Thermal aging of cast austenitic stainless steel elbow fittings results in embrittlement, that is, a decrease in the ductility, impact strength, and fracture toughness of the material.

The fully aged fracture toughness properties for 80 years of plant service used revised correlations per NUREG/CR-4513 Revision 2 (Reference 4.7.7.7) in predicting the fracture toughness properties for the primary loop elbow fittings based on primary coolant loop operating temperatures. The fully aged condition is applicable for plants operating at beyond 15 EFPY for the RCS loop A351-CF8M materials (elbows for Turkey Point Units 3 and 4). The PTN units are currently operating at greater than 33 EFPY. Therefore, the use of the fracture toughness correlations described herein are applicable for the fully aged or saturated condition of the Turkey Point Units 3 and 4 elbow materials made of A351-CF8M to demonstrate stability of the reactor coolant system due to any postulated cracks for 80 years of plant service.

Specific factors that may potentially generate stress corrosion cracking have been verified including the existence of Alloy 82/182. Since there is no Alloy 82/182 in the Turkey Point Units 3 and 4 primary loop piping, potential of primary water stress corrosion cracking can be precluded in Turkey Point Units 3 and 4 for 80 years of plant service.

Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which LBB crack stability evaluations were made. Through-wall flaw sizes were postulated at the critical locations that would cause leakage at a rate ten times the leakage detection system capability. Including the requirement for margin of applied loads, large margins against flaw instability were demonstrated for the postulated flaw sizes. A design transient set that bounds the PTN design transients was utilized in the fatigue crack growth analysis. The analysis concluded that fatigue crack growth for the SPEO is negligible. The LBB analysis revision has demonstrated compliance with LBB technology for the PTN reactor coolant system piping for 80 years of plant operation based on a plant specific analysis. The LBB evaluation also demonstrated that dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis of the Turkey Point Units 3 and 4 for the 80 year plant life.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The reactor coolant system primary loop piping LBB analysis has been projected to the end of the SPEO.

4.7.4 Leak-Before-Break Analysis for Class 1 Auxiliary Piping

TLAA Description

A leak-before-break analysis of the Class 1 auxiliary lines was performed as part of the extended power uprate (EPU) (Reference 4.7.7.8) demonstrating acceptable results for the current 60-year period of operation

Considering the LBB postulated crack stability analysis is related to the period of plant operation, the LBB analysis is a TLAA.

TLAA Evaluation

A leak-before-break (LBB) evaluation for the following Class 1 auxiliary lines at Turkey Point Units 3 and 4 was completed to support the EPU. These lines are attached to the reactor coolant loop (RCL) and span from the connection to the RCL to the first isolation valve or the pressurizer as applicable:

(1) 10-inch diameter accumulator lines – 3 lines (one per RCL connected to cold leg)

(2) 12-inch pressurizer surge line – 1 line attached to “B” loop (connected to hot leg)

(3) 14-inch residual heat removal line – 1 line attached to “C” loop in Unit 3 and “A” loop in Unit 4 (connected to hot leg)

The LBB analysis for these lines has been updated to address operation during the SPEO (80 years) (Reference 4.7.7.8). The evaluation was performed to eliminate consideration of the dynamic effects of the postulated large pipe rupture for these auxiliary lines. The LBB evaluation was performed in accordance with the 10 CFR Part 50, Appendix A GDC-4 and NUREG-1061, Vol. 3 (Reference 4.7.7.9) as supplemented by NUREG-0800, Standard Review Plan 3.6.3 (Reference 4.7.7.10).

The methodology used in determining LBB capabilities of the above lines at Turkey Point Units 3 and 4 consisted of several steps. First, the relationship between the critical through-wall flaw length and the applied stress (or moments) was determined on a generic basis for circumferential flaws. The critical flaw size as used herein refers to the through-wall flaw length that becomes unstable under a given set of applied loads. Critical flaw sizes were calculated using the net limit load (net section plastic collapse) approach with conservative material properties. NUREG-1061 requires that the load combination considered in determining the through-wall flaw length include the normal operating loads (NOP), which consists of internal pressure, dead weight, and thermal expansion loads, plus the safe shutdown earthquake (SSE). Once the NOP+SSE load for a given location is known, the critical flaw length can be determined from the generic relationship. The “leakage flaw size” was determined as the minimum of one half the critical flaw size with a factor of unity on normal operating plus SSE loads. Thus, the leakage flaw size as referred herein maintains a safety factor of 2 on the critical flaw size under normal plus SSE loads.

Leakage rates were determined as a function of stress (or moment) on a generic basis for a given through-wall flaw length. NUREG-1061, Vol. 3 requires that the NOP loads be used to determine the leakage. Given the relationships between the leakage flaw size versus NOP+SSE moments and leakage flaw size versus NOP moments, for a particular leak rate, a relationship was developed between the NOP+SSE moments and the NOP moments that would result in a particular leak rate. This results in the bounding analysis curve. The actual piping NOP+SSE and NOP loads were then used to determine if the combination of those loads would meet that leak rate. This particular scheme is very convenient for determining whether or not a particular leak rate will be met for a piping system with many nodal points and associated moments, such as the auxiliary RCL piping lines considered in this evaluation.

A fatigue crack growth analysis was also performed to determine the growth of postulated semi-elliptical, inside surface flaws with an initial size based on ASME Code, Section XI (Reference 4.7.7.11) acceptance standards. This showed that crack growth due to cyclic loadings was not significant such that it could be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP described in Section B.2.3.1. In addition, a fatigue crack growth analysis was performed to show that a through-wall crack would not grow significantly, hereby, insuring that the leakage size flaw will not grow to the critical crack size.

The following summary of the LBB evaluation is formatted per the “Recommendations for Application of the LBB Approach” in the NUREG-1061 Vol. 3 executive summary:

(a) The three piping systems considered in this evaluation are constructed of A 376 Type 316 stainless steel piping. At the operating temperature of these piping lines of 550°F to 653°F, this material is very ductile and it is not susceptible to cleavage-type fracture. In addition, these systems have been shown not to be susceptible to the effects of corrosion, high cycle fatigue or water hammer.

(b) Loadings have been determined from the original piping analysis, and are based upon pressure, dead weight, thermal expansion, and safe shutdown earthquake. All stress locations in these piping systems from the connection to the RCL to the first isolation valve or pressurizer, as applicable, were considered.

(c) Minimum ASME Code material properties were used to establish conservative lower bound stress-strain properties to be used in the evaluations. For the fracture toughness properties, lower-bound generic industry material properties for the piping and welds have been conservatively used in the evaluations.

(d) Crack growth analysis was conducted at the most critical locations on the evaluated piping, considering the cyclic stresses predicted to occur over the life of the plant. For a hypothetical flaw with aspect ratio of 10:1 and an initial flaw depth of 12.5 percent of pipe wall, the final flaw size after considering all plant transients for both 60 years and 80 years of operation is less than ASME Code Section XI allowable flaw size of 75 percent. Hence, fatigue crack growth is well within the allowable flaw size for the auxiliary RCL piping.

(e) The LBB evaluation was performed for leakage rates of 2 gpm, 5 gpm and 10 gpm. All piping locations considered in the evaluation exhibit a minimum leakage rate of 10 gpm based on the normal operating and normal plus dynamic loads. NUREG-1061 Vol. 3 recommends that the leakage detection system be capable of measuring leakage rates 1/10 of the minimum leakage rate. The plant leak detection capability for both Units 3 and 4 is 1 gpm, thereby satisfying the leakage rate requirement.

(f) Each of the piping systems considered in the evaluation is less than NUREG criteria of 51.2 feet in length and is not geometrically complex.

(g) Crack growth of a leakage size crack in the length direction due to a seismic event was small compared to the total circumference and insignificant compared to the margin between the leakage-size crack size and the critical crack size.

(h) For all locations, the critical size circumferential crack was determined for the combination of absolute values of normal operating plus SSE loads. The leakage size flaw was chosen such that its length was no greater than the critical crack size reduced by a factor of two for conservatism. Axial cracks were not considered as they are known to exhibit much higher leakage and more margin than circumferentially oriented cracks.

(i) Another LBB acceptance criterion is, for all locations, determine the critical crack size for the combination of 1.4 times the normal plus SSE loads and select the leakage crack no greater than this critical crack size. Based on previous experience, this criterion is always bounded by the criterion of (h) above. Hence, in the evaluation, only the evolution based on criterion of (h) is performed.

(j-n) No special testing was conducted to determine material properties for fracture mechanics evaluation. Instead, ASME Code minimum properties were utilized in the evaluations. The material properties so determined have been shown to be applicable near the upper range of normal plant operation and exhibit ductile behavior at these temperatures.

(o) Limit load analysis as outlined in NUREG-0800, SRP 3.6.3, was utilized in the evaluation in order to determine the critical flaw sizes since the materials involved in this evaluation are stainless steel piping.

Thus, the three Class 1 auxiliary piping systems evaluated for Turkey Point Units 3 and 4 qualify for the application of leak-before-break analysis to demonstrate that it is very unlikely that the piping could experience a large pipe break prior to leakage detection. Results of the evaluation show that for all applicable pipe stresses, leak-before-break can be justified for a plant leak detection system of 1 gpm.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The Class 1 auxiliary piping LBB analysis has been projected to the end of the SPEO.

4.7.5 Code Case N-481 Reactor Coolant Pump Integrity Analysis

TLAA Description

To support the EPU project, Westinghouse performed an evaluation of the Code Case N-481 RCP integrity analysis to identify if it is acceptable for the current extended operating period for PTN. The results of the evaluation concluded that the previous RCP integrity analysis conclusions documented in WCAP-13045 (Reference 4.7.7.12) and WCAP-15355

(Reference 4.7.7.13) for the RCP casings remain valid for the 60-year licensed operating period at EPU conditions. Based on these conclusions, no aging management program beyond the examinations required by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program described in Section B.2.3.1 is required to manage the thermal embrittlement for the RCP casings.

Considering this analysis is related to the period of plant operation, the analysis is a TLAA.

TLAA Evaluation

To demonstrate continued compliance during the subsequent period of operation, the analyses associated with the application of Code Case N-481 to the reactor coolant pump casing during the SPEO were re-evaluated by the Pressurized Water Reactor Owner's Group (Reference 4.7.7.14), copies of which are included in Enclosure 4 (non-proprietary) and Enclosure 5 (proprietary).

The Pressurized Water Reactor Owner's Group evaluation provides continued justification of the fracture mechanics integrity analysis in WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems," for application to SLR. The fracture mechanics evaluation for SLR provided in this report, a copy of which is provided in Enclosure 4 (non-proprietary) and Enclosure 5 (proprietary) allows plants to continue performing visual inspections, in lieu of volumetric inspections, for RCP casings as incorporated in the ASME Section XI code.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The PTN Code Case N-481 RCP integrity analysis has been projected to the end of the SPEO.

4.7.6 <u>Crane Load Cycle Limit</u>

TLAA Description

A review of design specifications was performed for cranes within the scope of SLR. Crane design includes considerations for frequency of operation and expected size of loads, relative to their maximum load capacity. As a result, cranes are given an expected maximum number of design cycles over their life, which also correlates to a number of cycles on structural members.

Since the maximum number of design load cycles over the current 60-year life of the cranes provide the basis for acceptability of the design for cyclic operation, these cyclic analyses are considered TLAAs. Therefore, the load cycles experienced over the SPEO need to be evaluated.

TLAA Evaluation

At Turkey Point Units 3 and 4, the following cranes within the scope of SLR are identified as having TLAAs:

- Reactor building polar cranes
- Spent fuel cask cranes
- Intake structure bridge cranes (also called intake area gantry cranes or intake structure cranes)
- Turbine gantry cranes (also called turbine cranes)
- Charging pump monorails
- Safety injection pump monorails
- Main steam platform monorails
- Reactor cavity manipulator cranes (also called fuel handling manipulator cranes)
- Fuel transfer machines (only the portions that require aging management as determined by the operating experience report)
- Spent fuel bridge cranes
- Fuel pool bulkhead monorails
- Intake cooling water (ICW) valve pit rigging beam
- Turbine plant cooling water (TPCW) basket strainer monorail

Metal fatigue (fatigue stress) results from repeated loading. Routinely, a load or stress is applied and completely or partially removed or reversed repeatedly. This manner of loading is important if high stresses are repeated for a few cycles or if lower stresses are repeated many times.

<u>All Cranes except Spent Fuel Bridge Cranes</u>

This evaluation is used to determine if a cyclic limit must be placed on the operational life of the subject cranes to ensure safe operation. Although the fatigue criterion in place during the manufacturing of the cranes is not explicitly addressed in EOCI-61 (Reference 4.7.7.15), proven analytical methods were used as a source of design input. Since EOCI -61 does not explicitly address fatigue, a comparison was made with the fatigue provisions of the sixth edition of the AISC Manual of Steel Construction (Reference 4.7.7.16), which is the code of record for structural design, in order to determine the allowable number of cycles of loading that are inherent in the EOCI -61 criteria.

For up to 2,000,000 cycles of maximum load, Section 1.7.3 of the AISC, Manual of Steel Construction requires that the allowable stresses be based on the use of A7 steel using Sections 1.5 and 1.6 of the specification. It also stipulates that these allowables be compared to the algebraic difference between the maximum computed stress and the minimum computed stress, but not be less than those required to support either the maximum or minimum computed stress in accordance with Sections 1.5 or 1.6.

The cranes covered by this calculation are configured so that the minimum computed stress is effectively zero. In other words, there is no stress reversal. Therefore, the maximum loading controls the design of the structural elements (maximum stress).

Thus, the cranes are acceptable for use of up to 2,000,000 cycles of maximum loads. For an 80-year period of operation, this equates to 68 cycles per day which is far more than any of these cranes would experience during the SPEO.

Spent Fuel Bridge Cranes

The Spent Fuel Bridge Cranes were replaced in 1990. Design of the Spent Fuel Bridge Cranes was in accordance with CMAA-70 (Reference 4.7.7.17), with added seismic requirements.

Per the AISC, Manual of Steel Construction (Reference 4.7.7.16) maximum stresses developed in the main structural elements and their connections are minimal relative to the strength and fatigue allowables. The only element with significant stress levels is a connection plate on the upper walkway. The maximum stress in this element for loads inclusive of the walkway is approximately 20 ksi. If this stress is conservatively considered totally reversing, the resulting stress range is within the allowable for Service Class A Crane. Therefore, the cranes are acceptable for use of up to 200,000 cycles of maximum loads. For original license renewal, the projected number of cycles for these cranes was 16,000. Applying a simple 80/60 multiplier, the total number of cycles for SLR would be conservatively estimated to be 22,000. This is well below the design cycles of 200,000.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The analyses associated with crane design, including fatigue, remain valid for the SPEO.

4.7.7 References

4.7.7.1 NRC Information Notice 87-44, Supplement 1: “Thimble Tube Thinning in Westinghouse Reactors”, March 28, 1988.

4.7.7.2 NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors”, July 26, 1988.

4.7.7.3 WCAP-14237, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Turkey Point Units 3 and 4 Nuclear Power Plant,” December 1994.

4.7.7.4 Nuclear Regulatory Commission Docket #'s 50-250 and 50-251 Letter from Richard P. Croteau, Project Manager, Project Directorate II-I, Division of Reactor Projects-I/II, NRC, to Mr. J. H. Goldberg, President, Florida Power and Light Company, Subject: “Turkey Point Units 3 and 4, Approval to Utilize Leak-Before-Break Methodology for Reactor Coolant System Piping (TAC Nos. M91494 and M91495),” dated June 23, 1995.

4.7.7.5 WCAP-15354, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Turkey Point Units 3 and 4 Nuclear Power Plant For the 60 Year Plant Life (License Renewal Program),” Revision 0, January 2000.

4.7.7.6 WCAP-15354-P/NP, “Technical Justification for Eliminating Primary Loop Pipe Rupture as the Structural Design Basis for Turkey Point Units 3 and 4 Nuclear Power Plants for the Subsequent License Renewal Time-Limited Aging Analysis Program (80 Years) Leak-Before-Break Evaluation,” Revision 1, August 2017 (Enclosure 4, Attachment 11).

4.7.7.7 NUREG/CR-4513, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems,” Revision 2, U.S. Nuclear Regulatory Commission, Washington, DC, May 2016.

4.7.7.8 Structural Integrity Associates Engineering Report No. 0901350.401, Revision 3, “Leak-Before-Break Evaluation - Accumulator, Pressurizer Surge, and Residual Heat Removal Lines, Turkey Point Units 3 and 4,” September 2017 (Enclosure 4, Attachment 12).

4.7.7.9 NUREG-1061, Volumes 1-5, “Report of the U. S. Nuclear Regulatory Commission Piping Review Committee,” prepared by the Piping Review Committee, NRC, April 1985.

4.7.7.10 NUREG-0800, “U.S. Nuclear Regulatory Commission Standard Revision Plan, Office of Nuclear Reactor Regulation, Section 3.6.3, Leak-Before-Break Evaluation Procedure,” August 1987.

4.7.7.11 ASME Boiler and Pressure Vessel Code, Section XI, 2001 Edition with Addenda through 2003.

4.7.7.12 WCAP-13045, Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems.

4.7.7.13 WCAP-15355, A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4.

4.7.7.14 PWROG-17033-P/NP, Revision 0, Update for Subsequent License Renewal: WCAP-13045, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems”, October 2017 (Enclosure 4, Attachment 13).

4.7.7.15 Specification E.O.C.I.-61, Electric Overhead Crane Institute, Inc., 1961.

4.7.7.16 AISC, Manual of Steel Construction, 6th Edition.

4.7.7.17 Specification CMAA -70, Crane Manufacturers Association of America, Inc., 1994.

Appendix A

Updated Final Safety Analysis Report Supplement

Turkey Point Nuclear Plant Units 3 and 4
Subsequent License Renewal Application

Note: Sections in Appendix A have been numbered as they will be when inserted into the UFSAR as Chapter 17.

Attachment 1 to Appendix A has additional UFSAR changes.

TABLE OF CONTENTS

LIST OF TABLES

17.0 AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSIS ACTIVITIES

17.1 INTRODUCTION

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a Final Safety Analysis Report (FSAR) supplement. This chapter comprises the Updated Final Safety Analysis Report (UFSAR) supplement of the Turkey Point (PTN) Subsequent License Renewal Application (SLRA) and includes the following sections:

- Section 17.1.1 contains a listing of the PTN aging management programs (AMPs) for subsequent license renewal (SLR) in the order of NUREG-2191 programs, that is NUREG-2191 Chapter X, NUREG-2191 Chapter XI, and a site-specific PTN AMP, including the status of the programs at the time the SLRA was submitted.
- Section 17.1.2 contains a listing of the time-limited aging analysis (TLAA) summaries.
- Section 17.1.3 contains a discussion stating the relationship between the Florida Power & Light Company (FPL) Quality Assurance (QA) Program at PTN and the AMPs' corrective actions, confirmation process, and administrative controls elements.
- Section 17.1.4 contains a summary of the PTN Operating Experience (OE) Program.
- Section 17.2 contains a summary of the PTN programs used for managing the effects of aging. These AMPs are associated with either NUREG-2191 Chapter X, Chapter XI, or are PTN site-specific.
- Section 17.3 contains a summary of the TLAAs applicable to the subsequent period of extended operation (SPEO).
- Section 17.4 contains the PTN SLR Commitment List and the AMPs' planned implementation schedule.

The integrated plant assessment for SLR identified new and existing AMPs necessary to provide reasonable assurance that systems, structures, and components (SSCs) within the scope of SLR will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the SPEO. The SPEO is defined as 20 years from the current renewed operating license expiration date.

17.1.1 Aging Management Programs

AMPs for PTN SLR are listed in Table 17-1 and described in Section 17.2. The AMPs are listed chronologically as they appear in NUREG-2191, with the Chapter X AMPs first, followed by the Chapter XI AMPs, and ending with the only PTN site-specific AMP, Pressurizer Surge Line Fatigue. The PTN AMPs are categorized as either existing AMPs or new AMPs for SLR. The existing PTN AMPs are renamed and enhanced as necessary to more closely align with AMPs described in NUREG-2191.

Table 17-1 below reflects the status of the PTN AMPs at the time of the SLRA submittal. Regulatory commitments, which include AMP enhancements and implementation schedules for PTN AMPs are identified in the PTN SLR Commitment List within Section 17.4.

Table 17-1
List of PTN Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
X.M1	Fatigue Monitoring (Section 17.2.1.1)	Existing
X.M2	Neutron Fluence Monitoring (Section 17.2.1.2)	Existing
X.S1	Concrete Containment Unbonded Tendon Prestress (Section 17.2.1.3)	Existing
X.E1	Environmental Qualification of Electric Equipment (Section 17.2.1.4)	Existing
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section 17.2.2.1)	Existing
XI.M2	Water Chemistry (Section 17.2.2.2)	Existing
XI.M3	Reactor Head Closure Stud Bolting (Section 17.2.2.3)	Existing
XI.M4	BWR Vessel ID Attachment Welds Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M5	Not Applicable (Deleted from NUREG-2191)	N/A
XI.M6	Not Applicable (Deleted from NUREG-2191)	N/A
XI.M7	BWR Stress Corrosion Cracking Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M8	BWR Penetrations Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M9	BWR Vessel Internals Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M10	Boric Acid Corrosion (Section 17.2.2.4)	Existing
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (Section 17.2.2.5)	Existing
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (Section 17.2.2.6)	New
XI.M16A	Reactor Vessel Internals (Section 17.2.2.7)	Existing
XI.M17	Flow-Accelerated Corrosion (Section 17.2.2.8)	Existing

Table 17-1 (Continued)
List of PTN Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.M18	Bolting Integrity (Section 17.2.2.9)	Existing
XI.M19	Steam Generators (Section 17.2.2.10)	Existing
XI.M20	Open-Cycle Cooling Water System (Section 17.2.2.11)	Existing
XI.M21A	Closed Treated Water Systems (Section 17.2.2.12)	Existing
XI.M22	Boraflex Monitoring Not Applicable (PTN U3 and U4 do not credit Boraflex as a neutron absorber in their criticality analyses.)	N/A
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section 17.2.2.13)	Existing
XI.M24	Compressed Air Monitoring (Section 17.2.2.14)	Existing
XI.M25	BWR Reactor Water Cleanup System Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M26	Fire Protection (Section 17.2.2.15)	Existing
XI.M27	Fire Water System (Section 17.2.2.16)	Existing
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks (Section 17.2.2.17)	Existing
XI.M30	Fuel Oil Chemistry (Section 17.2.2.18)	Existing
XI.M31	Reactor Vessel Material Surveillance (Section 17.2.2.19)	Existing
XI.M32	One-Time Inspection (Section 17.2.2.20)	New
XI.M33	Selective Leaching (Section 17.2.2.21)	New
XI.M35	ASME Code Class 1 Small-Bore Piping (Section 17.2.2.22)	Existing
XI.M36	External Surfaces Monitoring of Mechanical Components (Section 17.2.2.23)	Existing
XI.M37	Flux Thimble Tube Inspection (Section 17.2.2.24)	Existing
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section 17.2.2.25)	New

Table 17-1 (Continued)
List of PTN Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.M39	Lubricating Oil Analysis (Section 17.2.2.26)	Existing
XI.M40	Monitoring of Neutron-Absorbing Materials other than Boraflex (Section 17.2.2.27)	Existing
XI.M41	Buried and Underground Piping and Tanks (Section 17.2.2.28)	New
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section 17.2.2.29)	New
XI.S1	ASME Section XI, Subsection IWE (Section 17.2.2.30)	Existing
XI.S2	ASME Section XI, Subsection IWL (Section 17.2.2.31)	Existing
XI.S3	ASME Section XI, Subsection IWF (Section 17.2.2.32)	Existing
XI.S4	10 CFR Part 50, Appendix J (Section 17.2.2.33)	Existing
XI.S5	Masonry Walls (Section 17.2.2.34)	Existing
XI.S6	Structures Monitoring (Section 17.2.2.35)	Existing
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section 17.2.2.36)	Existing
XI.S8	Protective Coating Monitoring and Maintenance (Section 17.2.2.37)	Existing
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.38)	Existing
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits (Section 17.2.2.39)	New
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.40)	New

Table 17-1 (Continued)
List of PTN Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.41)	New
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.42)	New
XI.E4	Metal Enclosed Bus Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E5	Fuse Holders Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (Section 17.2.2.43)	New
XI.E7	High-Voltage Insulators (Section 17.2.2.44)	New
N/A – PTN Site-Specific Program	Pressurizer Surge Line Fatigue (Section 17.2.3.1)	Existing

17.1.2 Time-Limited Aging Analyses

The TLAA summaries applicable to PTN during the SPEO are identified in Table 17-2 and described in the sections subordinate to Section 17.3.

Table 17-2
List of Time-Limited Aging Analyses

Category (Section)	#	Time-Limited Aging Analyses Name	Section
Reactor Vessel Neutron Embrittlement (17.3.2)	1	Neutron Fluence Projections	17.3.2.1
	2	Pressurized Thermal Shock	17.3.2.2
	3	Upper-Shelf Energy	17.3.2.3
	4	Adjusted Reference Temperature	17.3.2.4
	5	Pressure-Temperature Limits and Low Temperature Overpressure (LTOP) Setpoints	17.3.2.5
Metal Fatigue (17.3.3)	6	ASME Boiler and Pressure Vessel Code, Section III, Class 1 Components	17.3.3.1
	7	ANSI B31.1 and ASME Boiler and Pressure Vessel Code, Section III, Class 3 Piping	17.3.3.2
	8	Environmentally Assisted Fatigue	17.3.3.3
	9	Reactor Vessel Underclad Cracking	17.3.3.4
	10	Reactor Coolant Pump Flywheel	17.3.3.5
Environmental Qualification of Electrical Equipment (17.3.4)	11	Environmental Qualification of Electrical Equipment	17.3.4
Concrete Containment Unbonded Tendon Prestress (17.3.5)	12	Concrete Containment Unbonded Tendon Prestress	17.3.5
Containment Liner Plate and Penetrations Fatigue Analysis (17.3.6)	13	Containment Liner Plate and Penetrations Fatigue Analysis	17.3.6
Other Site-Specific TLAAs (17.3.7)	14	Bottom-Mounted Instrumentation Thimble Tube Wear	17.3.7.1
	15	Emergency Containment Cooler Tube Wear	17.3.7.2
	16	Leak-Before-Break for Reactor Coolant System Piping	17.3.7.3
	17	Leak-Before-Break Class 1 Auxiliary Piping	17.3.7.4
	18	Code Case N-481 Reactor Coolant Pump Integrity Analysis	17.3.7.5
	19	Crane Load Cycle Limit	17.3.7.6

17.1.3 Quality Assurance Program and Administrative Controls

The FPL Quality Assurance (QA) Program for PTN implements the requirements of 10 CFR Part 50, Appendix B, and is consistent with the summary in Appendix A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)," of NUREG-2192. The FPL QA Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related SSCs and commodity groups that are included within the scope of the AMPs. Generically, the three elements are applicable as follows.

The corrective action, confirmation process, and administrative controls of the FPL QA Program are applicable to all AMPs and activities during the SPEO. The FPL QA Program procedures, review and approval processes, and administrative controls are implemented, as described in the FPL Topical QA Report, in accordance with the requirements of 10 CFR Part 50, Appendix B. The FPL QA Program applies to all structures and components (SCs) that credited for in a PTN AMP. Corrective actions and administrative (document) control for both safety-related and nonsafety-related SCs are accomplished in accordance with the established PTN corrective action program and document control program, and are applicable to all AMPs and activities during the SPEO. The confirmation process is part of the corrective action program and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspections required by the confirmation process are documented in accordance with the corrective action program.

17.1.4 Operating Experience Program

The PTN OE Program captures the OE from site-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the FPL QA Program. This OE program also meets the provisions of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff."

The PTN OE Program interfaces with and relies on active participation in the Institute of Nuclear Power Operations (INPO) OE program, as endorsed by the U.S. Nuclear Regulatory Commission (NRC). In accordance with these programs, all incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development 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 site-specific and industry OE. Site-specific OE associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the PTN OE Program.

17.2 AGING MANAGEMENT PROGRAMS

17.2.1 NUREG-2191 Chapter X Aging Management Programs

This section provides UFSAR summaries of the SLR AMPs associated with TLAAs.

17.2.1.1 Fatigue Monitoring

The existing PTN Fatigue Monitoring AMP provides an acceptable basis for managing fatigue of components that are subject to the fatigue or cycle-based loading TLAAs that remain valid in accordance with 10 CFR 54.21(c)(1)(iii). This AMP also assures that the corrective action specified in the program is taken if the actual number of cycles approaches 80 percent of the analyzed values. Fatigue of components is managed by monitoring and tracking the number of occurrences and severity of design basis transients to ensure they remain within the limits of the fatigue analyses, which in turn ensure that the analyses remain valid. Cycle-based fatigue analyses for which this AMP is used include, but are not limited to, the following: (a) cumulative usage factor (CUF) analyses or their equivalent performed in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements for specific mechanical or structural components; (b) fatigue analysis calculations for assessing environmentally-assisted fatigue (CUF_{en}); (c) implicit fatigue analyses, as defined in the American National Standards Institute (ANSI) B31.1 design code or ASME Code Section III rules for Class 2 and 3 components; (d) fatigue flaw growth analyses that are based on cyclical loading assumptions; and (e) fracture mechanics analyses that are based on cycle-based loading assumptions.

This AMP also relies on the PTN Water Chemistry AMP to provide monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

17.2.1.2 Neutron Fluence Monitoring

The PTN Neutron Fluence Monitoring AMP, previously the fluence and uncertainty calculation portion of the PTN Reactor Vessel Integrity Program, is an existing program that ensures the continued validity of the neutron fluence analyses and related TLAAs. In so doing, this AMP also provides an acceptable basis for managing aging effects attributable to neutron fluence irradiation in accordance with 10 CFR 54.21(c)(1)(iii). This AMP monitors neutron fluence for reactor pressure vessel (RPV) and reactor vessel internals (RVI) components to verify the continued acceptability of existing irradiation embrittlement (IE) and related analyses. This AMP includes periodic updates to ensure and demonstrate that RPV IE and related analyses remain within applicable limits defined in the CLB.

Neutron fluence is considered to be a TLAA and is a time-limited input to a number of RPV IE analyses that are TLAAs for SLR. AMP results are compared to the neutron fluence parameter inputs used in the IE analyses. This includes: (a) pressurized thermal shock (PTS) analyses required by 10 CFR 50.61; (b) upper-shelf energy (USE) and the associated equivalent margins analysis (EMA) required by Section IV.A.1 of 10 CFR Part 50, Appendix G; and (c) pressure-temperature (P-T) limits and low-temperature over-pressure protection (LTOP) limits.

Guidance on acceptable methods and assumptions for determining reactor vessel neutron fluence is described in NRC Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," which originated as Draft Regulatory Guide (DG)-1053. The methods developed and approved using the guidance contained in RG 1.190 are specifically intended to determine neutron fluence in the cylindrical region of the RPV surrounding the effective height of the active fuel.

This AMP evaluates the RPV surveillance capsule dosimetry data and updates the fluence projections in the cylindrical RPV locations, as needed. The Westinghouse Commercial Atomic Power (WCAP)-14040-A methodology, which complies with RG 1.190, is used for PTN fluence determinations in the cylindrical RPV region that surrounds the effective height of the active fuel, the RPV beltline. Calculational methods, benchmarking, qualification, and surveillance data are monitored to maintain the adequacy and ascribed uncertainty of RPV beltline neutron fluence calculations and thereby the associated RPV IE analyses:

(a) This approved methodology uses geometrical and material input data, and equilibrium fuel cycle operational data, to determine characteristics of the neutron flux in the core.

(b) Additionally, these data are used to determine the neutron transport to the vessel and into the reactor cavity.

(c) Capsule surveillance data is used for qualification of the neutron fluence calculation.

(d) The same WCAP-14040-A methodology was used for the fluence calculations performed in support of the PTN Unit 3 and Unit 4 extended power uprates (EPUs).

The PTN calculations of neutron fluence also factor into other analyses or evaluations that assess irradiation-related aging effects. Examples include: (a) determination of the (extended) RPV beltline, for which neutron fluence is projected to exceed 1 x 1017 neutrons/square centimeter (n/cm2) (E > 1 MeV), as defined in Regulatory Issue Summary (RIS) 2014-11; (b) susceptibility of RVI components to neutron radiation damage mechanisms; and (c) dosimetry data obtained from the PTN Reactor Vessel Material Surveillance AMP. Estimates of neutron fluence for RPV regions significantly above and below the active fuel region of the core, and for RVI components, use the RG 1.190 adherent methodology as the base to provide conservative estimates and will include additional justification, consistent with related industry efforts, as necessary.

This AMP monitors in-vessel capsules and evaluates the dosimetry data, as needed. Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H, requirements through the PTN Reactor Vessel Material Surveillance AMP provide inputs to and may impact the neutron fluence monitoring results tracked by this AMP.

17.2.1.3 Concrete Containment Unbonded Tendon Prestress

The PTN Concrete Containment Unbonded Tendon Prestress AMP is an existing AMP that is part of the PTN Inservice Inspection (ISI) Program that is based on ASME Section XI, Subsection IWL, criteria, as supplemented by the requirements of 10 CFR 50.55a(b)(2)(viii). This AMP monitors and manages the loss of tendon prestress in the concrete containment prestressing system for the SPEO.

Loss of containment tendon prestressing forces is a TLAA evaluated in accordance with 10 CFR 54.21(c)(1)(iii). The PTN Concrete Containment Unbonded Tendon Prestress AMP, as part of the PTN ASME Section XI, Subsection IWL AMP, manages loss of containment tendon prestressing forces in the current period of extended operation (PEO). This TLAA AMP consists of the assessment of measured tendon prestressing forces from examinations performed through the PTN ASME Section XI, Subsection IWL AMP. The adequacy of the prestressing force for each tendon group based on type (i.e., hoop, vertical, and dome) and other considerations (e.g., geometric dimensions, whether affected by repair/replacement, etc.) establishes (a) acceptance criteria in accordance with Subsection IWL and (b) trend lines constructed based on the guidance provided in NRC IN 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The calculation of prestressing losses, predicted upper limits and predicted lower limits for each tendon group is in accordance with the guidelines of the NRC RG 1.35.1, "Determining Prestressing Forces or Inspection of Prestressed Concrete Containments."

The loss of concrete containment tendon prestressing forces is detected by comparing the measured data against the predicted force values from the respective containment tendon loss of prestress TLAA. Loss of prestressing forces are also detected by comparing the tendon force trend lines, constructed from surveillance measurements, against predicted force values. In addition to PTN Unit 3 and Unit 4 ASME Section XI, Subsection IWL examination requirements, all measured prestressing forces, up to the current examination, are plotted against time. The predicted lower limit (PLL), MRV, and trend-line curves are developed for each tendon group examined for the SPEO. The trend line represents the general variation of prestressing forces with time based on the actual measured forces in individual tendons of the specific tendon group. The trend line for each tendon group is constructed by regression analysis of measured prestressing forces in individual tendons of that group obtained from previous examinations. The inspections are conducted every five years (i.e., 1, 3, 5, 10, 15, 20, 25, 30, 35, 40, 45th year, etc.) on alternating units. The trend lines will be updated after each scheduled examination using methods consistent with RG 1.35.1.

The prestressing force trend line for each tendon group shall not cross the appropriate MRV curve prior to the next scheduled examination. In addition, the constructed trend line shall not cross the appropriate PLL curve for any of the tendon groups. In case any of the two precedent criteria fail, the cause shall be determined, evaluated and corrected in a timely manner. If acceptance criteria are not met, then either systematic re-tensioning of tendons or a reanalysis of the concrete containment is warranted so that the design adequacy of the containment is demonstrated.

17.2.1.4 Environmental Qualification of Electric Equipment

The existing PTN Environmental Qualification (EQ) of Electric Equipment AMP, previously the PTN EQ Program, implements the EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49, and manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. This AMP provides the requirements for the EQ of electrical equipment important to safety that could be exposed to harsh environment accident conditions as required by 10 CFR 50.49 and RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants." This AMP is established per the requirements of 10 CFR 50.49 to demonstrate that certain electrical components located in harsh plant environments (i.e., those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high-energy line breaks (HELBs), or a main steam line break (MSLB) inside or outside the containment, from elevated temperatures or high radiation or steam, or their combination) are qualified to perform their safety function in those harsh environments after the effects of inservice (operational) aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ, and that the equipment be demonstrated to function in the harsh environment, following aging.

Equipment covered by this AMP has been evaluated to determine if the existing EQ aging analyses can be projected to the end of the SPEO by reanalysis or additional analysis. When analysis cannot justify a qualified life in excess of the SLR period, then the component parts are replaced, refurbished, or requalified prior to exceeding the qualified life as required by 10 CFR 50.49. Aging evaluations for EQ equipment that specify a qualification of at least 60 years are TLAAs for SLR. The PTN EQ of Electrical Equipment AMP is implemented in accordance with 10 CFR 54.21(c)(1)(iii).

17.2.2 NUREG-2191 Chapter XI Aging Management Programs

This section provides UFSAR summaries of the NUREG-2191 Chapter XI programs credited for managing the effects of aging.

17.2.2.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP is an existing AMP that identifies and corrects degradation in Class 1, 2, and 3 pressure-retaining components and piping. The AMP manages the aging effects of loss of material, and cracking. The AMP provides inspection and examination of accessible components, including welds, pump casings, valve bodies, and pressure-retaining bolting. In accordance with 10 CFR 50.55a, ISI program plans documenting the examination and testing of Class 1, 2 and 3 components are prepared in accordance with the rules and requirements of ASME Section XI (latest approved edition). The PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP describes the long-term inspection program for Class 1, 2 and 3 components.

The PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD, AMP is updated at the end of the 120-month interval to the latest approved edition of the ASME Section XI Code identified by 10 CFR 50.55a 12 months prior to the end of the 120-month interval. All examinations and inspections performed in accordance with the program plan are documented by records and reports, which are submitted to the NRC as required by IWA-6000.

17.2.2.2 Water Chemistry

The PTN Water Chemistry AMP is an existing AMP, formerly a portion of the PTN Chemistry Control Program, that mitigates aging effects of loss of material due to corrosion, cracking due to stress corrosion cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to treated water. The PTN Water Chemistry AMP controls treated water for impurities (e.g., chloride, fluoride, and sulfate) that accelerate corrosion, and is generally effective in removing impurities from intermediate and high flow areas. This AMP includes periodic monitoring and control of the treated water in order to minimize loss of material or cracking based on the industry guidelines contained in Electric Power Research Institute (EPRI) 3002000505, “PWR Primary Water Chemistry Guidelines,” Revision 7, and EPRI 1016555, “PWR Secondary Water Chemistry Guidelines,” Revision 7. The PTN Water Chemistry AMP is augmented by the PTN One-Time Inspection AMP, to verify the AMP effectiveness in managing corrosion-susceptible components (i.e., components located in areas exposed to low or stagnant flow).

17.2.2.3 Reactor Head Closure Stud Bolting

The PTN Reactor Head Closure Stud Bolting AMP is an existing AMP, formerly part of the ASME Section XI, Subsections IWB, IWC and IWD, portion of the PTN ISI Program. This AMP provides (a) ISI in accordance with the requirements of ASME, Section XI, Subsection IWB, Table IWB-2500-1 and (b) preventative measures to mitigate cracking. This AMP is in accordance with the regulatory position delineated in NRC RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs." The scope of this AMP includes:

- Closure head nuts
- Closure studs
- Threads in the RPV flange
- Closure washers and bushings

17.2.2.4 Boric Acid Corrosion

The PTN Boric Acid Corrosion AMP is an existing AMP, previously the PTN Boric Acid Wastage Surveillance Program, that manages the aging effects of loss of material and mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. This AMP addresses the reactor coolant system (RCS) and SCs containing, or exposed to, borated water.

This AMP utilizes systematic inspections, leakage evaluations, and corrective actions for all components subject to AMR that may be adversely affected by some form of borated water leakage. This ensures that boric acid corrosion does not lead to degradation of pressure boundary, leakage boundary or structural integrity of components, supports, or structures, including electrical equipment in proximity to borated water systems. The effects of boric acid corrosion on reactor coolant pressure boundary materials in the vicinity of nickel alloy components are also addressed by the PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, which is associated with NUREG-2191 XI.M11B, “Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only).” Additionally, this AMP relies in part on the response to, and includes commitments to, NRC Generic Letter (GL) 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” to identify, evaluate, and correct borated water leaks that could cause corrosion damage. This AMP includes provisions to initiate evaluations and assessments when leakage is discovered by activities not associated with the program. This AMP also follows the guidance described in Section 7 of Westinghouse Commercial Atomic Power (WCAP)-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Inspection Program for Pressurized Water Reactors.”

17.2.2.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

The PTN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP is an existing AMP, previously the PTN Reactor Vessel Head Alloy 600 Penetration Inspection Program, that manages the aging effect of primary water stress corrosion cracking (PWSCC) for pertinent nickel alloy materials (Alloy 600/82/182) in the RCS pressure boundary. This AMP also addresses the OE of degradation due to PWSCC of components or welds constructed from those nickel alloys and exposed to primary coolant at elevated temperature. The scope of this AMP includes the following groups of components and materials:

(a) Nickel alloy components and welds identified in ASME Code Cases N-729 and N-722, as incorporated by reference in 10 CFR 50.55a, and;

(b) Components that are susceptible to corrosion by boric acid and may be impacted by leakage of boric acid from nearby or adjacent nickel alloy components previously described.

Visual examination of the Unit 3 and Unit 4 reactor vessel head external surfaces during outages and through the PTN Boric Acid Corrosion AMP are utilized to manage cracking. Future inspections of the reactor vessel heads are in accordance with ASME Code Case N-729-1, which has been included in the augmented ISI program, including the conditions listed in 10 CFR 50.55a. PTN will continue to participate in industry programs to ensure that PWSCC is managed for the SPEO.

17.2.2.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

The PTN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is a new AMP for the SPEO. This AMP augments the ASME Section XI inspections of RCS and connected components with service conditions above 250°C (482°F), in order to detect the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) piping components, including pump casings. CASS valve bodies are not included in the program. This AMP includes determination of the potential significance of thermal aging embrittlement of CASS components based on casting method, molybdenum content, and percent ferrite. For components where thermal aging embrittlement is potentially significant, aging management is accomplished through either:

(a) Qualified visual inspections, such as enhanced visual examination (EVT-1);

(b) A qualified ultrasonic testing (UT) methodology, or;

(c) A component-specific flaw tolerance evaluation in accordance with the ASME Code Section XI.

For pump casings, as an alternative to the screening and other actions described above, no further actions are needed. The original flaw tolerance evaluation performed as part of Pressurized Water Reactor Owners Group (PWROG) Code Case N-481 implementation is revised to be applicable for 80 years, as described in Section 17.3.7.5. The evaluation documents that the Code Case N-481 reactor coolant pump (RCP) integrity analysis has been projected to the end of the SPEO, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

Based on the results of the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, NRC, to Douglas Walters, Nuclear Energy Institute (NEI), screening for significance of thermal aging embrittlement is not required for valve bodies and the existing ASME Code Section XI inspection requirements are adequate for valve bodies.

17.2.2.7 Reactor Vessel Internals

The PTN Reactor Vessel Internals AMP is an existing AMP, based on the inspection and evaluation guidelines of EPRI Technical Report No. 1022863 (MRP-227-A). However, the inspection and evaluation guidelines in MRP-227-A were written for an operating period of 60 years. The MRP-227-A guidelines are supplemented through a gap analysis that identifies enhancements to the program that are needed to address an 80-year operating period. The inspection and evaluation guidelines of MRP-227-A, as modified by the gap analysis for the additional 20-year plant life, provided by FPLCORP020-REPT-078, "Aging Management Program Basis Document—Reactor Vessel Internals," are used to manage the applicable age-related degradation mechanisms, and listed as follows:

(a) Cracking, including SCC, irradiation-assisted stress corrosion cracking (IASCC), and cracking due to fatigue/cyclic loading;

(b) Loss of material induced by wear;

(c) Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement (IE);

(d) Changes in dimensions due to void swelling (VS) or distortion; and

(e) Loss of preload due to thermal and irradiation-enhanced stress relaxation and creep.

17.2.2.8 Flow-Accelerated Corrosion

The PTN Flow-Accelerated Corrosion AMP is an existing AMP that manages loss of material (wall thinning) caused by flow-accelerated corrosion (FAC). This AMP predicts, detects, monitors, and mitigates FAC wear in high-energy carbon steel piping associated with the main steam and turbine generators, and feedwater and blowdown systems, and is based on industry guidelines (Nuclear Safety Analysis Center document, NSAC-202L-R3, EPRI 1011231, and EPRI TR-112657) and industry OE. This AMP also includes analysis and baseline inspections; determination, evaluation, and corrective actions for affected components; and follow-up inspections.

The AMP is based on commitments made in FPL letter, L-89-265, which was in response to the NRC GL 89-08. This AMP relies on implementation of the EPRI guidelines in NSAC-202L-R3, "Recommendations for an Effective Flow Accelerated Corrosion Program (1015425)," and use of the predictive analytical software, CHECWORKS™.

The AMP includes:

(a) Identifying all FAC-susceptible piping systems and components;

(b) Developing FAC predictive models to reflect component geometries, materials, and operating parameters;

(c) Performing analyses of FAC models and, with consideration of OE, selecting a sample of components for inspections;

(d) Inspecting components;

(e) Evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and

(f) Incorporating inspection data to refine FAC models.

For SLR, the PTN FAC AMP will also manage wall thinning caused by erosion mechanisms in limited situations where periodic monitoring is used in lieu of eliminating the cause, typically a design or operational deficiency, in components that contain treated water (including borated water) or steam. These limited situations are based on site OE and will be monitored similar to other FAC locations that are not modeled.

17.2.2.9 Bolting Integrity

The PTN Bolting Integrity AMP is an existing AMP related to existing activities, which include the PTN Systems and Structures Monitoring Program and the PTN ASME Section XI Inservice Inspection Program (which covers safety related bolting). This AMP manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This AMP also manages submerged pressure-retaining bolting and closure bolting for piping systems that contain air or gas for which leakage is difficult to detect. This AMP does not include the reactor head closure studs or structural bolting, which are addressed by separate AMPs. This AMP relies on industry standards for comprehensive bolting maintenance as delineated in NUREG-1339, EPRI NP-5769, EPRI Report 1015336, and EPRI Report 1015337.

The preventive actions associated with this AMP include proper selection of bolting material; the use of appropriate lubricants and sealants in accordance with the guidelines of EPRI Report 1015336 and EPRI Report 1015337, along with additional recommendations from NUREG-1339; consideration of actual yield strength when procuring bolting material (e.g., ensuring any replacement or new pressure-retaining bolting has an actual yield strength of less than 150 ksi); lubricant selection (e.g., not allowing the use of molybdenum disulfide); proper torquing of bolts, checking for uniformity of the gasket compression after assembly; and application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, or engineering evaluation. These actions preclude loss of preload, loss of material, and cracking.

This AMP supplements the inspection activities required by ASME Code Section XI for ASME Code Class 1, 2 and 3 bolting. For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspections (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. Visual inspection methods are effective in detecting the applicable aging effects, and the frequency of inspection is adequate to ensure that actions are taken to prevent significant age-related degradation. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the PTN corrective action program (CAP). This AMP supplements the inspection activities required by ASME Code Section XI for ASME Code Class 1, 2 and 3 bolting. Pressure-retaining bolted connections are inspected at least once per refueling cycle as part of ASME Code Section XI leakage tests. For inaccessible components, accessible components with similar materials and environments will be inspected. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow site procedures that include inspection parameters for items such as lighting and distance offset that provide an adequate examination. For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspections (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. Visual inspection methods are effective in detecting the applicable aging effects, and the frequency of inspection is adequate to ensure that actions are taken to prevent significant age-related degradation. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the PTN corrective action program. The inspection includes a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) or a maximum of 25 bolts per population at each unit.

Submerged closure bolting that precludes detection of joint leakage is inspected visually for loss of material during maintenance activities. Bolt heads are inspected when made accessible and bolt threads are inspected when joints are disassembled. In each 10-year period during SPEO, a representative sample of bolt heads and threads is inspected. If opportunistic maintenance activities do not provide access to 20 percent of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then the integrity of the bolted joint will be evaluated on a case-by-case basis using methods, such as periodic pump vibration measurements taken and trended or sump pump operator walkdowns performed to demonstrate that the pumps are appropriately maintaining sump levels.

Because leakage is difficult to detect for bolted joints that contain air or gas, the associated closure bolting will be evaluated on a case-by-case basis using one of the following methods:

- Inspections are performed consistent with that of submerged closure bolting;
- A visual inspection for discoloration is conducted (applies when leakage of the environment inside the piping systems would discolor the external surfaces);
- Monitoring and trending of pressure decay is performed when the bolted connection is located within an isolated boundary
- Soap bubble testing is performed; or
- Thermography testing is performed (applies when the temperature of the fluid is higher than ambient conditions).

For component joints that are not normally pressurized, the aging effects associated with closure bolting will be managed by checking the torque to the extent that the closure bolting is not loose.

Indications of aging are evaluated in accordance with Section XI of the ASME Code. Leaking joints do not meet acceptance criteria. When alternative inspections or testing is necessary, site-specific acceptance criteria will be used.

17.2.2.10 Steam Generators

The PTN Steam Generators AMP is an existing AMP, previously the PTN Steam Generator Integrity Program, which ensures steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. This AMP manages the aging of steam generator tubes, plugs, divider plates, interior surfaces of channel heads, tubesheets (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). However, the tube-to-tubesheet welds of the PTN steam generators are exempt from inspection and monitoring per the NRC Safety Evaluation Report (SER) (Turkey Point Nuclear Generating Station Unit Nos. 3 and 4-Issuance of Amendments Regarding Permanent Alternative Repair Criteria for Steam Generator Tubes, Accession Number ML12292A342, November 5, 2012) for permanent Alternate Repair Criteria (H*) for steam generator tubes.

The aging of steam generator pressure vessel welds is managed by other AMPs, such as the PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD, AMP (Section 17.2.2.1) and the PTN Water Chemistry AMP (Section 17.2.2.2).

The establishment of a steam generator program for ensuring steam generator tube integrity is required by the PTN Technical Specifications (TS), Sections 3/4.4.5 and 6.8.4.j. Additionally, Admin Control 6.8.4.j requires tube integrity to be maintained to specific performance criteria, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable tube repair methods, and leakage monitoring requirements. The nondestructive examination (NDE) techniques used to inspect steam generator components covered by this AMP are intended to identify components (e.g., tubes, plugs) with degradation that may need to be removed from service (e.g., tubes), repaired, or replaced, as appropriate.

The AMP is modeled after NEI 97-06, “Steam Generator Program Guidelines.” As such, this AMP incorporates of the following industry guidelines: EPRI-1013706, “PWR Steam Generator Examination Guidelines,” EPRI-1022832, “PWR Primary-to-Secondary Leak Guidelines,” EPRI 1014986, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” EPRI 1016555, “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” EPRI-3002007571, “Steam Generator Integrity Assessment Guidelines,” and EPRI 1025132, “Steam Generator In-Situ Pressure Test Guidelines.”

The AMP performs volumetric examination on steam generator tubes in accordance with the requirements in the PTN TS to detect aging effects, if they should occur. This AMP also performs general visual inspections of the steam generator heads (internal surfaces) looking for evidence of cracking or loss of material (e.g., rust stains) at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections. The AMP also includes foreign material exclusion as a means to inhibit wear degradation, and secondary side maintenance activities, such as sludge lancing, for removing deposits that may contribute to component degradation.

17.2.2.11 Open Cycle Cooling Water System

The PTN Open-Cycle Cooling Water (OCCW) System AMP is an existing AMP, previously the PTN Intake Cooling Water (ICW) System Inspection Program, that relies, in part, on implementing the PTN response to the recommendations of NRC GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” to provide reasonable assurance that the effects of aging on the OCCW system (or ICW system at PTN), are managed for the SPEO.

NRC GL 89-13 defines the OCCW system as a system or systems that transfer heat from safety-related SSCs to the ultimate heat sink (UHS). This AMP is comprised of the aging management aspects of the PTN response to NRC GL 89-13, including:

(a) A program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling;

(b) A program to verify heat transfer capabilities of all safety-related heat exchangers cooled by the OCCW system, and;

(c) A program for routine inspection and maintenance to provide reasonable assurance that loss of material, corrosion, erosion, protective coating failure, cracking, fouling, and biofouling cannot degrade the performance of safety-related systems serviced by the OCCW system.

This AMP manages aging effects, which include loss of material due to various corrosion mechanisms, SCC, and biological fouling of components in raw water systems, such as the PTN ICW system, by using a combination of preventive, condition monitoring, and performance monitoring activities. These activities include:

(a) Surveillance and control techniques to in the OCCW system or SCs serviced by the OCCW system;

(b) Inspection of components for signs of loss of material, corrosion, erosion, cracking, fouling, and biofouling, and;

(c) Testing of the heat transfer capability of heat exchangers that remove heat from components important to safety.

The PTN OCCW System AMP also manages the loss of coating integrity for internal coatings of piping within the scope of this AMP. This AMP includes the guidance provided in the “scope of program” elements of the PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP to manage loss of coating integrity.

17.2.2.12 Closed Treated Water System

The PTN Closed Treated Water Systems AMP is an existing AMP, formerly a portion of the PTN Chemistry Control Program and the PTN Systems and Structures Monitoring Program. This AMP manages the aging effects of loss of material due to corrosion, cracking due to SCC, and reduction of heat transfer due to fouling of the internal surfaces of piping, piping components, piping elements and heat exchanger components fabricated from any material and exposed to treated water. The aging effects are minimized or prevented by controlling the chemical species that cause the underlying mechanism(s) that result in these aging effects. This AMP is a mitigation program that also includes a condition monitoring program to verify the effectiveness of the mitigation activities. The AMP consists of:

(a) Water treatment, including 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 and microbiological testing of the water to demonstrate that the water treatment program maintains the water chemistry and microbiological organisms within acceptable guidelines and;

(c) Component inspections/testing to determine the presence or extent of component degradation, and corrective actions as required based on these inspections.

This AMP uses the 2013 version of EPRI TR-3002000590, “Closed Cooling Water Chemistry Guideline,” as applicable, and includes microbiological testing. EPRI TR-3002000590 is used rather than the NUREG-2191 recommended standard, EPRI 1007820, because EPRI TR-3002000590 supersedes EPRI 1007820. The newer EPRI guideline document encompasses new technology and captures lessons learned and industry OE.

17.2.2.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is an existing AMP (formerly part of the PTN Systems and Structures Monitoring Program). This AMP evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of SLR. This AMP also addresses the inspection and monitoring of crane-related SCs to provide reasonable assurance that the handling system does not affect the intended function of nearby safety-related equipment. This AMP includes periodic visual inspections to detect loss of material due to corrosion, deformation, wear, cracking, fouling, loss of seal, and change in material properties, and indications of loss of preload for load handling bridges, structural members, structural components, and bolted connections. This AMP also includes corrective actions as required based on these inspections. This AMP relies on the guidance in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," ASME B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” ASME B30.11, “Monorails and Underhung Cranes,” and other appropriate standards in the ASME B30 series. These cranes also comply with the maintenance rule requirements provided in 10 CFR 50.65.

17.2.2.14 Compressed Air Monitoring

The PTN Compressed Air Monitoring AMP is an existing AMP, that was formerly encompassed by the plant instrument air monitoring activities. This AMP manages loss of material due to corrosion in compressed air systems and supplied components within the scope of SLR through (a) preventive monitoring for water (moisture) and other contaminants, and (b) opportunistic inspection of component internal surfaces for indications of corrosion. This AMP ensures that compressed air system conditions remain as designed, such that moisture is not collecting in compressed air systems or supplied components and that air quality is retained so that loss of material due to corrosion is not occurring in the “dry air”. Moisture sensors at the outlet of the air dryers continuously monitor inline dew point. Opportunistic internal visual inspections of critical components and other components are performed for signs of loss of material due to corrosion. The PTN Compressed Air Monitoring AMP is based on commitments made in response to NRC GL 88-14, and incorporates industry guidance (such as INPO SOER 88-01, ASME OM-2012, ANSI/ISA 7.0.1, and EPRI TR-101847), as warranted.

17.2.2.15 Fire Protection

The PTN Fire Protection AMP is an existing AMP, formerly a portion of the PTN Fire Protection Program. This AMP manages aging effects (loss of material, cracking, and loss of seal) associated with fire barriers and non-water suppression systems (halon systems). The PTN Fire Protection AMP includes fire barrier inspections. The fire barrier inspection portion of this AMP requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors, fire damper assemblies, as well as periodic visual inspection and functional tests of fire-rated doors so that their operability is maintained. The PTN Fire Protection AMP also includes periodic inspection and testing of the halon fire suppression systems. See UFSAR Section 9.6.1 for additional information on the PTN Fire Protection Program.

With respect to preventive actions, PTN has adopted the National Fire Protection Association (NFPA) 805 fire protection program to meet the requirements of 10 CFR 50.48(c) and ensure that regulatory requirements are met for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing SSCs important to safety.

Inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material. The acceptance criteria include:

(a) No visual indications (outside of those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals;

(b) No significant indications of cracking and loss of material of fire barrier walls, ceilings, floors, and in other fire barrier materials;

(c) No visual indications of missing parts, holes, and wear; and

(d) No deficiencies in the functional tests of fire doors (i.e., the door swings easily, freely, and achieves positive latching).

Periodic inspections and hydro testing of the halon fire suppression system are performed to demonstrate that it is functional, and the surface condition of the halon system components is inspected for corrosion, nozzle obstructions, and other damage.

Visual inspection of at least 10 percent of each type of sealed penetration is performed at a frequency of every 18 months, which is in accordance with the NRC-approved fire protection program. Visual inspections on fire-rated assemblies (fire barrier walls, ceilings, floors, and other fire barrier materials including structural steel fire proofing) are conducted at a frequency of at least once every three years. Periodic visual inspections and functional tests are conducted on fire doors and their closing mechanism and latches are verified functional at least once per 12 months. Visual inspection on the fire damper assemblies are conducted at a frequency of once every three years.

The results of inspections and functional testing of the in-scope fire protection equipment are collected, analyzed, and summarized by engineers in health reports. The system and program health reporting procedures identifies adverse trends and prescribes preemptive corrective actions to prevent further degradation or future failures. When performance degrades to unacceptable levels, the PTN CAP is utilized to drive improvement. During the inspection of penetration seals, if any sign of abnormal degradation is detected within the sample, the inspection sample size is expanded, in accordance with the approved PTN fire protection program, to include an additional 10 percent of each type of sealed penetration.

17.2.2.16 Fire Water System

The PTN Fire Water System AMP is an existing AMP, formerly a portion of the PTN Fire Protection Program. This AMP is a condition monitoring program that manages aging effects associated with water-based fire protection system (FPS) components. This AMP manages loss of material, cracking, and flow blockage due to fouling by conducting periodic visual inspections, tests, and flushes performed in accordance with the 2011 Edition of NFPA 25. Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA 25. In addition to NFPA codes and standards, portions of the water-based FPS that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect are subjected to augmented testing beyond that specified in NFPA 25, including:

(a) periodic system full flow tests at the design pressure and flow rate or internal visual inspections and (b) piping volumetric wall-thickness examinations.

The water-based FPS is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions are initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material is detected, and is sufficient enough to obstruct piping or sprinklers, then the material is removed, the source of the material is identified, and the source is corrected. Inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes for an adequate examination. See UFSAR Section 9.6. for more information on the PTN Fire Protection Program.

17.2.2.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing condition monitoring AMP that manages loss of material. One-time inspections were performed by the PTN Field Erected Tanks Internal Inspection Program for original license renewal. Other plant documents control inspections or activities of the various outdoor storage tanks in the scope of the AMP. The condensate storage tanks (CSTs), common demineralized water storage tank (DWST), refueling water storage tanks (RWSTs), and Unit 3 emergency diesel generator (EDG) fuel oil storage tank (FOST) comprise the scope of this AMP.

This AMP includes thickness measurements of tank bottoms to detect degradation and ensure corrosion from the inaccessible undersides will not cause a loss of intended tank function. The AMP also includes periodic visual inspection of tank internal surfaces and external tank-to-concrete interface. Inspections are conducted in accordance with site/fleet procedures that include inspection parameters such as lighting, distance, offset, and surface condition.

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP also manages loss of material on the exterior and interior surfaces of metallic aboveground tanks founded on concrete. The tanks in the scope of the AMP are steel and are un-insulated. External surfaces, other than the tank-to-concrete interface, are accessible and inspected through the External Surfaces Monitoring of Mechanical Components AMP (Section 17.2.2.23) or Structures Monitoring AMP (Section 17.2.2.35). The Water Chemistry AMP (Section 17.2.2.2) and Fuel Oil Chemistry AMP (Section 17.2.2.18) are mitigative AMPs whose effectiveness is verified by the One-Time Inspection AMP (Section 17.2.2.20). Protective coatings/linings inside the tanks in the scope of the PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP are inspected for loss of lining integrity by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section 17.2.2.29).

17.2.2.18 Fuel Oil Chemistry

The PTN Fuel Oil Chemistry AMP is an existing AMP that was formerly a portion of the PTN Chemistry Control Program. This AMP manages loss of material and fouling in piping and components exposed to an environment of diesel fuel oil by verifying the quality of fuel oil and controlling fuel oil contamination, as well as periodic draining, cleaning, and inspection of tanks. The scope of the PTN Fuel Oil Chemistry AMP includes the Unit 3 and 4 EDG FOSTs, the Unit 3 and 4 EDG day tanks, the Unit 3 EDG skid-mounted tanks, piping and other metal components subject to AMR that are exposed to an environment of diesel fuel oil. The scope of the AMP also includes piping, piping components, and fuel tanks associated with the diesel-driven fire pump and the diesel-driven standby steam generator feedwater (SSGF) pump that are exposed to an environment of diesel fuel. Acceptance criteria for fuel oil quality parameters are in accordance with the PTN TS, ASTM D 975, and NRC RG 1.137.

This AMP includes (a) surveillance and maintenance procedures to mitigate corrosion, and (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the PTN TS LCO 3/4.8.1. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks, and by verifying the quality of new oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, effectiveness is verified by the One-Time Inspection AMP (Section 17.2.2.20) to provide reasonable assurance that significant degradation is identified and adequately managed and that the component intended function is maintained during the SPEO.

17.2.2.19 Reactor Vessel Material Surveillance

The PTN Reactor Vessel Material Surveillance AMP is an existing AMP, formerly a portion of the PTN Reactor Vessel Integrity Program. This AMP includes withdrawal and testing of the X_4 surveillance capsule, identified in UFSAR Table 4.4-2. This capsule is demonstrated as being within one to two times the peak reactor vessel neutron fluence of interest at the end of the SPEO in the TLAAs for USE, PTS, and P-T temperature limits. The surveillance program adheres to the requirements of 10 CFR Part 50, Appendix H, as well as the American Society for Testing Materials (ASTM) standards incorporated by reference in 10 CFR Part 50, Appendix H. The surveillance capsule withdrawal schedule is per Attachment 1 of the PTN Reactor Material Surveillance Program. Surveillance capsules are designed and located to permit insertion of replacement capsules.

Title 10 of the Code of Federal Regulations (10 CFR) Part 50, Appendix H, requires implementation of a reactor vessel material surveillance program when the peak neutron fluence at the end of the design life of the vessel is projected to exceed 10^{17} n/cm^2 (E > 1 MeV). The purpose of the PTN Reactor Vessel Material Surveillance AMP is to monitor the changes in fracture toughness to the ferritic reactor vessel beltline materials. As described in RIS 2014-11, beltline materials are those ferritic reactor vessel materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the license period (for example, the SPEO), which are evaluated to identify the extent of neutron radiation embrittlement for the material. The surveillance capsules contain reactor vessel material specimens and are located near the inside vessel wall in the beltline region so that the specimens duplicate, as closely as possible, the neutron spectrum, temperature history, and maximum neutron fluence experienced at the reactor vessel's inner surface. Because of the location of the capsules between the reactor core and the reactor vessel wall, surveillance capsules typically receive neutron fluence exposures that are higher than the inner surface of the reactor vessel. This allows surveillance capsules to be withdrawn and tested prior to the inner surface receiving an equivalent neutron fluence so that the surveillance test results bound the corresponding operating period in the capsule withdrawal schedule.

FPL was a member of the Babcock & Wilcox Owners Group (B&WOG) reactor vessel working group. The B&WOG designed an irradiation surveillance program (Master Integrated Reactor Vessel Program, MIRVP) in which member materials are irradiated at host plants. PTN materials are being irradiated in both reactor vessels (Units 3 and 4) at the site and in the MIRVP. The MIRVP Charpy values and direct fracture toughness (master curve) data are used as supplemental data. To date, this program has developed one set of Charpy values and two sets of irradiated "master curve" data relative to the PTN beltline materials. The PWROG is now the mechanism for the previous B&WOG reactor vessel working group activities. FPL is a member of the PWROG. Recent changes to the MIRVP are currently being evaluated by the NRC. However, the implementation of the MIRVP in this Reactor Vessel Material Surveillance AMP is only for supplemental data and is not a part of the NRC approved surveillance program. This AMP relies fully on onsite capsules.

The objective of the PTN Reactor Vessel Material Surveillance AMP is to provide sufficient material data and dosimetry to (a) monitor IE to a neutron fluence level that is greater than the projected peak neutron fluence of interest projected to the end of the SPEO, and (b) provide adequate dosimetry monitoring during the SPEO. Dosimetry monitoring during the SPEO is performed as described in the PTN Neutron Fluence Monitoring AMP.

The PTN Reactor Vessel Material Surveillance AMP is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in the upper-shelf energy (USE) as a function of neutron fluence and irradiation temperature. The data from this surveillance program are used to monitor neutron IE of the reactor vessel, and are inputs to the neutron embrittlement TLAAs. The PTN Reactor Vessel Material Surveillance AMP is also used in conjunction with the proposed PTN Neutron Fluence Monitoring AMP.

All surveillance capsules, including those previously withdrawn from the reactor vessel, must meet the test procedures and reporting requirements of the applicable ASTM standards referenced in 10 CFR Part 50, Appendix H, to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the surveillance capsule withdrawal schedule must be approved by the NRC prior to implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3.

17.2.2.20 One-Time Inspection

The PTN One-Time Inspection AMP is a new AMP that consists of a one-time inspection of selected components to accomplish the following:

(a) Verify the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO. The aging effects evaluated are loss of material, cracking and fouling.

(b) Confirm the insignificance of an aging effect for situations in which additional confirmation is appropriate using inspections that verify unacceptable degradation is not occurring.

(c) Trigger additional actions that ensure the intended functions of affected components are maintained during the SPEO.

The PTN One-Time Inspection AMP manages systems and components that credit the PTN Water Chemistry (Section 17.2.2.2), Fuel Oil Chemistry (Section 17.2.2.18), and Lubricating Oil Analysis (Section 17.2.2.26) AMPs.

Determination of the sample size is based on 20 percent of the components in each material-environment-aging effect group up to a maximum of 25 components per unit. The sample size of components will also be based on OE. Identification of inspection locations are based on the potential for the aging effect to occur. Examination techniques are established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria are based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. The need for follow-up examinations are evaluated based on inspection results if age-related degradation is found that could jeopardize an intended function before the end of the SPEO. This AMP also performs an augmented inspection of the transition cone weld of the steam generators to verify the effectiveness of the water chemistry program.

The PTN One-Time Inspection AMP will not be used for SCs with known, age-related degradation mechanisms, or when the material-environment-aging effect group in the SPEO is not expected to be equivalent to that in the prior operating period. In these cases, periodic site-specific inspections are performed. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with site-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions.

17.2.2.21 Selective Leaching

The PTN Selective Leaching AMP is a new AMP. This AMP is a condition monitoring AMP that includes inspection for components that may be susceptible to loss of material due to selective leaching by demonstrating the absence of selective leaching (dealloying) of materials.

This AMP includes a one-time inspection for components exposed to a treated water environment when site-specific OE has not revealed selective leaching in these environments. To date, no site-specific OE at PTN has revealed selective leaching, therefore, a one-time inspection is required. The AMP also includes periodic inspections for components that are exposed to raw water, waste water, lubricating oil, or soil environments and opportunistic inspections whenever components are opened, or whenever buried or submerged surfaces are exposed, and these periodic inspections are conducted at an interval of no greater than every 10 years during the SPEO.

The scope of this AMP includes components made of gray cast iron, ductile iron, and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to a raw water, treated water, waste water, lubricating oil, or soil environment. Depending on environment, the AMP includes one-time, or opportunistic and periodic visual inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques (e.g., chipping, scraping). Destructive examinations of components to determine the presence of and depth of dealloying through-wall thickness are also conducted. These techniques can determine whether loss of material due to selective leaching is occurring and whether selective leaching will affect the ability of the components to perform their intended function for the SPEO. Inspections are conducted in accordance with site-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions. When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the SPEO, additional inspections are performed.

Each of the one-time and periodic inspections for these populations at each unit comprises a 3 percent sample or a maximum of 10 components. Gray cast iron and ductile iron components will be visually and mechanically inspected, the rest will be visually inspected. In addition, for gray cast iron exposed to raw water and ductile iron exposed to raw water (i.e., the only populations having 35 or more components), two destructive examinations will be performed for each material and environment population in each 10-year inspection interval at each unit. For each population with less than 35 susceptible components, one destructive examination will be performed.

When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the SPEO, additional inspections are performed if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of additional inspections is equal to the number of failed inspections for each material and environment population, with a minimum of five additional visual and mechanical inspections when visual and mechanical inspection(s) did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria.

17.2.2.22 ASME Code Class 1 Small-Bore Piping

The PTN ASME Code Class 1 Small-Bore Piping AMP is an existing AMP that was formerly the PTN Small Bore Class 1 Piping Inspection Program. This AMP is a condition monitoring AMP for detecting cracking in small-bore, ASME Code Class 1 piping. This AMP supplements the ISI specified by ASME Code, Section XI, for certain ASME Code Class 1 piping that is less than 4 inches in nominal pipe size (NPS) and greater than or equal to 1 inch NPS. The scope of this

AMP includes pipes, fittings, branch connections, and all full and partial penetration (socket) welds. This AMP includes measures to verify that degradation is not occurring, thereby confirming that there is no need to manage age related degradation.

Industry OE demonstrates that welds in ASME Code Class 1 small-bore piping are susceptible to stress corrosion cracking (SCC) and cracking due to thermal or vibratory fatigue loading. Such cracking is frequently initiated from the inside diameter of the piping; therefore, volumetric examinations are needed to detect cracks. However, ASME Code, Section XI, generally does not call for volumetric examinations of this class and size of piping. This AMP supplements the ASME Code, Section XI, examinations with volumetric examinations, or alternatively, destructive examinations, to detect cracks that may originate from the inside diameter of butt welds, socket welds, and their base metal materials. The examination schedule and extent is based on site-specific OE and whether actions have been implemented that would successfully mitigate the causes of any past cracking.

A one-time inspection to detect cracking resulting from thermal and mechanical loading, vibration, or intergranular stress corrosion of full penetration welds are performed by volumetric examination. A one-time inspection to detect cracking in socket welds are performed by either volumetric or destructive examination. These inspections will provide additional assurance that either aging of small-bore ASME Code Class 1 piping is not occurring or the aging is insignificant. Should evidence of cracking be revealed by the one-time inspections, a periodic inspection plan is implemented in accordance with NUREG-2191 Table XI.M35-1.

A volumetric inspection of a sample (sample size as specified in NUREG-2191, Table XI.M35-1) of small bore Class 1 piping and nozzles are performed to determine if cracking is an aging effect requiring management during the SPEO. Per NUREG-2191, Table XI.M35-1, PTN is a Category A plant because it has no history of age-related cracking. Per category A, the inspection will be a one-time inspection with a sample size of at least 3 percent, up to a maximum of 10 welds, of each weld type, for each operating unit using a methodology to select the most susceptible and risk-significant welds. For socket welds, destructive examination may be performed in lieu of volumetric examinations. Because more information can be obtained from a destructive examination than from nondestructive examination, credit will be taken for each weld destructively examined equivalent to having volumetrically examined two welds. If an acceptable volumetric technique cannot be used to perform a volumetric inspection, then a destructive examination is performed. For each socket weld that is destructively examined, credit may be taken as being equivalent to volumetrically examining two socket welds. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions is then established. The inspections are performed prior to the SPEO for PTN Units 3 and 4.

17.2.2.23 External Surfaces Monitoring of Mechanical Components

The PTN External Surfaces Monitoring of Mechanical Components AMP is an existing AMP that was formerly a portion of the PTN Systems and Structures Monitoring Program and other site-specific programs. This AMP is a condition monitoring program that manages loss of material, cracking, hardening or loss of strength (of elastomeric components), loss of seal, reduced thermal insulation resistance, loss of preload for ducting closure bolting, reduction of heat transfer due to fouling (air to fluid heat exchangers), and reduction of thermal insulation resistance due to moisture intrusion. This AMP also inspects the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces.

This AMP provides for periodic visual inspection and examination for degradation of accessible surfaces of specific SSCs, and corrective actions, as required, based on these inspections. Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) are conducted. Surface examinations or ASME Code Section XI VT-1 examinations are conducted to detect cracking of stainless steel (SS) and aluminum components.

For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength or reduction in impact strength is used to augment the visual examinations conducted under this AMP. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are periodically inspected every 10 years during the SPEO. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with site-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

17.2.2.24 Flux Thimble Tube Inspection

The PTN Flux Thimble Tube Inspection AMP is an existing AMP that was formerly the PTN Thimble Tube Inspection Program. This AMP is a condition monitoring program that is used to inspect for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. This AMP manages the aging effect of material loss due to fretting wear.

The flux thimble tube inspection associated with this AMP encompasses all of the flux thimble tubes that form part of the RCS pressure boundary. This AMP monitors flux thimble tube wall thickness to detect loss of material from the flux thimble tubes during the SPEO. The flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. Periodic Bobbin coil eddy current testing (ECT) is used to monitor for loss of material and wear of the flux thimble tubes during the SPEO. This inspection AMP implements the recommendations of NRC Bulletin 88 09, "Thimble Tube Thinning in Westinghouse Reactors."

17.2.2.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new condition monitoring program that manages the aging effects of loss of material, cracking, erosion, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of elastomeric and polymeric materials. Some of inspections and activities within the scope of this new AMP were previously performed by the PTN Systems and Structures Monitoring Program, the PTN Periodic Surveillance and Preventive Maintenance Program, and other site-specific programs.

This AMP consists of visual inspections and, when appropriate, surface examinations of specific SSCs with accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to potentially aggressive environments. These environments include air, air with borated water leakage, condensation, gas, diesel exhaust, fuel oil, lubricating oil, and any water-filled systems not managed by another AMP. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP. This AMP may also perform surface examinations or ASME Code Section XI VT-1 examinations to detect and manage cracking due to SCC in aluminum and SS components exposed to aqueous solutions and air environments containing halides.

These internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the SPEO, 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 unit is inspected for the in-scope aging effects. The maximum of 19 components per unit for inspection is used in lieu of 25 components per unit due to PTN being a two-unit plant with sufficiently similar operating conditions at each unit (e.g., flowrate, chemistry, temperature, and excursions), similar time in operation for each unit, similar water sources, and similar operating frequency.

Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service and the severity of operating conditions. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP.

Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with site-specific procedures, including inspection parameters for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Where practical, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). Where qualitative acceptance criteria are used, the criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions. Corrective actions are performed as required based on the inspection results.

This AMP is not intended for use on components in which recurring internal corrosion is evident based on a search of site-specific OE conducted during the SLRA development. Except for elastomers and flexible polymeric components, aging effects associated with items within the scope of the Open-Cycle Cooling Water System AMP (Section 17.2.2.11), Closed Treated Water Systems AMP (Section 17.2.2.12), and Fire Water System AMP (Section 17.2.2.16) are not managed by the PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.

17.2.2.26 Lubricating Oil Analysis

The PTN Lubricating Oil Analysis AMP is an existing AMP, previously performed as part of the plants' predictive maintenance. This AMP 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. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also indicate in-leakage and corrosion product buildup.

17.2.2.27 Monitoring of Neutron-Absorbing Materials other than Boraflex

The PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP, formerly the PTN Metamic® Insert Surveillance Program, is an existing condition monitoring program that is implemented to ensure that degradation of the neutron-absorbing material used in spent fuel pools, that could compromise the criticality analysis, will be detected. This AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to ensure that the required 5 percent subcriticality margin is maintained during the SPEO. This AMP consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or in situ.

This AMP addresses the aging management of the PTN spent fuel pools' credited neutron absorbing materials, which include Metamic® inserts and Boral® panels.

17.2.2.28 Buried and Underground Piping and Tanks

The PTN Buried and Underground Piping and Tanks AMP is a new AMP. This AMP is a condition monitoring program that manages the aging effects associated with the external surfaces of buried piping.

With respect to this AMP, the following terms are used:

- “Buried” piping and tanks are in direct contact with soil or concrete.
- “Underground” piping and tanks are below grade and contained in a tunnel or vault, exposed to air, and located where inspection access is limited.

There are no buried or underground tanks at PTN.

This AMP manages the external surface condition of buried piping for loss of material and cracking for the external surfaces of buried piping fabricated of cast iron, concrete, carbon steel and SS through preventive measures (e.g., coatings, backfill, and compaction), mitigative measures (e.g., electrical isolation between piping and supports of dissimilar metals, etc.), and periodic inspection activities (e.g., direct visual inspection of external surfaces, protective coatings, wrappings and quality of backfill) during opportunistic or directed excavations. The number of inspections is based on the effectiveness of the preventive and mitigative actions.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria, such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the SPEO, an increase in the sample size is conducted. Direct visual inspection are performed on the external surfaces, protective coatings, wrappings, quality of backfill and wall thickness measurements using NDE techniques. Additional inspections are performed on steel piping in lieu of fire main testing. The fire water system jockey pump activity (or a similar parameter) will be monitored for unusual trends. The table below provides additional information related to inspections. Preventative Action Category F has been selected for monitoring steel piping (which includes cast iron piping) during the initial monitoring period since the cathodic protection system will not be operational during that time period. The number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in Table XI.M41-2, adjusted for a 2-Unit plant site.

Material	**Parameter(s) Monitored**	**No. of Inspections**	**Notes**
Steel (Category F)	Loss of Material	11	GALL-SLR Report AMP XI.M41 Table XI.M41-2 quantity increased by 2 in lieu of fire main flow testing
Stainless Steel	Loss of Material Cracking	2	
Cementitious	Loss of Material Cracking	2	

Loss of material is monitored by visual inspection of the exterior and wall thickness measurements of the piping. Wall thickness is determined by an NDE technique such as UT.

17.2.2.29 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP, although some of its activities and inspections were formerly a portion of the PTN Periodic Surveillance and Preventative Maintenance Program, the PTN Intake Cooling Water Inspection Program, the PTN Field Erected Tanks Internal Inspection Program, and other site-specific programs. This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.

This AMP 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 component or downstream component CLB intended function(s). Visual inspections are conducted on external surfaces when applicable. Where visual inspection of the coated/lined surfaces determines that the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection.

For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in NRC RG 1.54, “Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants,” including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces.

Active peeling and delamination are not acceptable. Blisters are not acceptable unless a coating specialist has determined them to be surrounded by sound material 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 qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54. 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.

17.2.2.30 ASME Section XI, Subsection IWE

The PTN ASME Section XI, Subsection IWE, AMP is an existing AMP that was formerly the PTN ASME Section XI, Subsection IWE, Inservice Inspection Program. This condition monitoring

AMP is in accordance with ASME Code Section XI, Subsection IWE, and consistent with 10 CFR 50.55a, “Codes and Standards,” with supplemental recommendations. This AMP includes periodic visual, surface, and volumetric examinations, where applicable, of the metallic liner of Class CC pressure-retaining components and their integral attachments. This AMP also provides inspection and examination of containment surfaces, moisture barriers, pressure retaining bolting, and pressure retaining components for signs of degradation, damage, and irregularities, including discernable liner plate bulges. In conjunction with 10 CFR Part 50 Appendix J AMP (Section 17.2.2.33), this AMP manages loss of material, loss of leak tightness, loss of sealing, and loss of preload, as well as cracking (of dissimilar metal welds associated with penetration sleeves and fuel transfer tube). Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements and corrected in accordance with the corrective action program.

Coated areas are examined for distress of the underlying metal shell or liner. Acceptability of inaccessible areas of the concrete containment steel liner is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas. Inspection results are compared with prior recorded results in acceptance of components for continued service. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the condition is determined and that corrective action is taken to preclude recurrence. The examination of containment, Class MC and Class CC components, is in accordance with ASME Section XI, Subsection IWE, 2001 edition 2003 addenda, as mandated and modified by 10 CFR 50.55a.

If triggered by site-specific OE, this AMP also includes a one-time supplemental volumetric examination by sampling both randomly selected and focused liner locations susceptible to corrosion that are inaccessible from one side.

PTN has no pressure-retaining components subject to cyclic loading without CLB fatigue analysis; therefore, a supplemental surface examination to detect cracking for such pressure-retaining components is not required.

17.2.2.31 ASME Section XI, Subsection IWL

The PTN ASME XI, Subsection IWL, AMP is an existing AMP that was formerly the PTN ASME Section XI, Subsection IWL, ISI Program. This AMP is in accordance with ASME Code Section XI, Subsection IWL, and consistent with 10 CFR 50.55a, "Codes and Standards." The inspections associated with this AMP assess the quality and structural performance of the containment structure post-tensioning system components. The current program complies with ASME Code Section XI, Subsection IWL, 2001 Edition through 2003 Addenda (Reference B.3.132), supplemented with the applicable requirements of 10 CFR 50.55a(b)(2). This program is consistent with provisions in 10 CFR 50.55a that specify the use of the ASME Code edition in effect 12 months prior to the start of the start of the inspection interval. PTN will use the ASME Code edition consistent with the provisions of 10 CFR 50.55a during the SPEO. In accordance with 10 CFR 50.55a(g)(4)(ii), 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 twelve months before the start of the inspection interval.

This AMP manages the aging effects of loss of material and confirms the results of the containment tendon loss of prestress TLAA. This AMP includes inspection of tendon and anchorage hardware surfaces and measurement of tendon force and elongation. This AMP also includes inspection of containment reinforced concrete above ground for evidence of concrete degradation. This AMP also consists of:

(a) Periodic visual inspection of accessible concrete surfaces for the reinforced and prestressed concrete containment structure;

(b) Periodic visual inspection and sample tendon-testing of un-bonded post-tensioning system components for signs of degradation, assessment of damage, and corrective actions and;

(c) Testing of the tendon corrosion protection medium and free water.

Loss of tendon prestress is a TLAA; the results of which are confirmed by this AMP. Measured tendon lift-off forces in select sample tendons are compared to predicted tendon forces calculated in accordance with NRC RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." The Subsection IWL requirements are supplemented to include quantitative acceptance criteria for the evaluation of concrete surfaces based on the "Evaluation Criteria" provided in Chapter 5 of American Concrete Institute (ACI) 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." Inspection results are compared with prior recorded results in acceptance of components for continued service.

Inaccessible containment concrete surfaces, such as foundations below groundwater, are managed by the PTN Structures Monitoring AMP.

17.2.2.32 ASME Section XI, Subsection IWF

The PTN ASME Section XI, Subsection IWF AMP is an existing condition monitoring program that consists of periodic visual examination of ASME Section XI Class 1, 2, and 3 piping and component support members for signs of degradation such as loss of material, and loss of mechanical function. Bolting for Class 1, 2, and 3, piping and component supports is also included and inspected for loss of material and for loss of preload. Associated sliding surfaces, and vibration isolation elements are also inspected.

The PTN ASME Section XI, Subsection IWF AMP provides inspection and acceptance criteria and meets the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI, 2007 edition with addenda through 2008, and 10 CFR 50.55a(b)(2) for Class 1, 2, 3 piping and components and their associated supports. The primary inspection method employed is visual examination. Non-destructive examination (NDE) indications are evaluated against the acceptance standards of ASME Code Section XI.

Examinations that reveal indications are evaluated. Examinations that reveal flaws or relevant conditions that exceed the referenced acceptance standard, are expanded to include additional examinations during the current outage. The scope of inspection for supports is based on sampling of the total support population. The sample size varies depending on the ASME Class. The largest sample size is specified for the most critical supports (ASME Class 1). The sample size decreases for the less critical supports (ASME Class 2 and 3). Tactile inspections of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect is also included.

The requirements of ASME Section XI, Subsection IWF are supplemented to include volumetric examination of high-strength bolting for cracking and a one-time inspection within 5 years prior to the SPEO of an additional 5 percent of piping supports from the remaining IWF population that are considered most susceptible to age-related degradation.

17.2.2.33 10 CFR Part 50, Appendix J

The PTN 10 CFR Part 50, Appendix J, AMP is an existing AMP that was formerly the PTN Containment Leak Rate Testing Program, although it was not previously credited for license renewal. This AMP is a performance monitoring program that monitors leakage rates through the containment pressure boundary, including the containment liner, associated welds, penetrations, isolation valves, fittings, and other access openings, in order to detect degradation of the containment pressure boundary. Additionally, 10 CFR 50, Appendix J, requires a general visual inspection of the accessible interior and exterior surfaces of the containment structures and components to be performed prior to any Type A test and at periodic intervals between tests based on the performance of the containment system.

17.2.2.34 Masonry Walls

The PTN Masonry Walls AMP is an existing AMP, formerly a portion of the PTN Systems and Structures Monitoring Program, currently implemented as part of the PTN Structures Monitoring AMP. This condition monitoring AMP is based on NRC Inspection and Enforcement (IE) Bulletin 80-11, “Masonry Wall Design,” and monitoring proposed by NRC Information Notice (IN) 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE 80-11,” for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained.

This AMP consists of periodic visual inspection of masonry walls within the scope of SLR to detect loss of material and cracking of masonry units and mortar. Masonry walls that are fire barriers are also managed by the Fire Protection program.

17.2.2.35 Structures Monitoring

The PTN Structures Monitoring AMP is an existing condition monitoring program that consists primarily of periodic visual inspections of plant SCs for evidence of deterioration or degradation, such as described in the American Concrete Institute (ACI) Standards 349.3R, ACI 201.1R, and

Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11. Quantitative acceptance criteria for concrete inspections are based on ACI 349.3R. Inspections and evaluations are performed using criteria derived from industry codes and standards contained in the plant CLB including but not limited to ACI 349.3R, ACI 318, SEI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications. The AMP includes preventive actions to ensure structural bolting integrity. Results from periodic inspections are trended. Due the presence of aggressive groundwater chemistry (Chlorides > 500 parts per million (ppm)), the AMP includes site-specific evaluations, destructive testing, if warranted, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed five years.

17.2.2.36 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The PTN Inspection of Water Control Structures Associated with Nuclear Power Plants AMP is an existing AMP, formerly a portion of the PTN Systems and Structures Monitoring Program. The AMP manages age-related degradation due to environmental conditions and the effects of natural phenomena that may affect water-control structures through periodic monitoring and maintenance activities. Although PTN has not formally committed to implement RG 1.127, this AMP addresses inspection of water-control structures, commensurate with RG 1.127.

The structures within the scope of the AMP are associated with emergency cooling systems and include the Intake Structure, Discharge Structure, and Cooling Canals. Structural steel and bolting associated with these structures is within the scope of the program inspections. The AMP performs periodic monitoring of water-control structures at least every five years so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner. The AMP also includes structural steel and structural bolting associated with water-control structures, and miscellaneous steel. Results that exceed the acceptance criteria for applicable parameters monitored or inspected are documented and a list of current deficiencies is maintained for trending and corrective action. Periodic inspections are adequate to detect degradation of water-control structures before a loss of an intended function. Qualifications of inspection and evaluation personnel for reinforced concrete water control structures are in accordance with ACI 349.3R.

PTN water control structures are exposed to aggressive ground water (Chlorides > 500 ppm); therefore, focused inspections of below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil is performed on an interval not to exceed five years. Submerged concrete structures may be inspected during periods of low tide, when dewatered or by using divers. Areas covered by silt, vegetation, or marine growth are not considered inaccessible, and are cleaned and inspected in accordance with the standard inspection frequency.

17.2.2.37 Protective Coating Monitoring and Maintenance

The PTN Protective Coating Monitoring and Maintenance AMP is an existing AMP that was formerly the PTN Service Level 1 Coatings Program, although it was not previously credited for license renewal. The PTN Protective Coating Monitoring and Maintenance AMP provides guidelines for establishing an inservice coatings monitoring program for Service Level I coating systems in accordance with ASTM D 5163. The AMP will use the aging management detection methods, inspection frequency, monitoring and trending, and acceptance criteria defined in ASTM D 5163-08, "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants."

Degraded coatings in the containment are assessed periodically to ensure post-accident operability of the Emergency Core Cooling System (ECCS). Proper maintenance of protective coatings inside containment is essential to the operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of ECCS suction strainers, which reduces flow through the system and could cause unacceptable head loss for the pumps. This AMP ensures that a monitoring and maintenance program is comparable to NRC RG 1.54, Revision 2, for the SPEO.

This AMP consists of guidance for inspection and maintenance of protective coatings. Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors) serve to prevent or minimize loss of material due to corrosion of carbon steel components and aids in decontamination.

17.2.2.38 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP is an existing AMP, formerly a portion of the PTN Containment Cable Inspection Program. This AMP applies to accessible non-EQ electrical cable and connection electrical insulation material within the scope of SLR subjected to an adverse localized environment (e.g., heat, radiation, or moisture). Adverse localized environments are identified through the use of an integrated approach, which includes, but is not limited to, a review of relevant site-specific and industry OE, field walkdown data, etc. Accessible non-EQ insulated cable and connections within the scope of SLR installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies indicating signs of reduced electrical insulation resistance. The first inspection for SLR is to be completed no earlier than 10 years prior to the SPEO and no later than six months prior to entering the SPEO. Recurring inspections are to be performed at least once every 10 years thereafter.

If visual inspections identify cable jacket and connection insulation surface anomalies, then testing may be performed. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. A sample population of cable and connection insulation is utilized if testing is performed. If testing is deemed necessary, a sample of 20 percent of each cable and connection type with a maximum sample size of 25 is tested. When acceptance criteria are not met, a determination is made as to whether the surveillance, inspection, or tests, including frequency intervals, need to be modified.

Electrical insulation material for cables and connectors previously identified and dispositioned during the first period of extended operation as subjected to an adverse localized environment are evaluated for cumulative aging effects during the SPEO.

17.2.2.39 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP is a new AMP. This AMP manages the aging effects of the applicable cables and connections in the following systems or sub-systems:

- Nuclear Instrumentation: excore source, intermediate, and power range
- Process Radiation Monitoring:
    - Containment air particulate monitors
    - Containment gas monitors
    - Control room HVAC emergency monitor (common)
    - Control room normal air intake monitor (common)

This AMP provides reasonable assurance that non-EQ cables and connections used in high-voltage, low-level current signal applications that are sensitive to reduction in electrical insulation resistance will perform their intended function consistent with the CLB through the SPEO.

In this AMP, either of two methods can be used to identify the existence of electrical insulation aging effects for cables and connections. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. In this method, the first reviews are completed prior to the SPEO and at least every 10 years thereafter. In the second method, direct testing of the cable system is performed when the calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results or findings of surveillance testing programs. In the second method, the test frequency of the cable system is determined based on engineering evaluation, but the test frequency is at least once every 10 years with the first test is to be completed prior to the SPEO.

17.2.2.40 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements

The PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible medium-voltage power cables (operating voltages of 2 kV to 35 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct-buried installations) non-EQ medium-voltage power cables within the scope of SLR exposed to wetting or submergence (i.e., significant moisture). Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long-term wetting or submergence over a continuous period), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that occurs for a limited time as drainage from either automatic or passive drains is not considered significant moisture for this AMP.

In-scope inaccessible medium-voltage power cables exposed to significant moisture are tested to determine the condition of the electrical insulation. One or more tests may be required based on cable application, construction, and electrical insulation material to determine the age degradation of the cable. The first tests for license renewal are to be completed no later than 6 months prior to the SPEO with subsequent tests performed at least once every six years thereafter. Inaccessible medium-voltage cables designed for continuous wetting or submergence are also included in this AMP for a one-time inspection and test.

This is a condition monitoring program. However, this AMP includes periodic actions to prevent inaccessible medium-voltage power cables from being exposed to significant moisture. Periodic actions to mitigate inaccessible medium-voltage cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduits, and removing water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspection frequencies are adjusted based on inspection results, including site-specific OE, but with a minimum inspection frequency of at least once annually. Inspections are also performed after event-driven occurrences, such as heavy rain or flooding. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults, are effective in preventing inaccessible cable exposure to significant moisture.

17.2.2.41 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements

The PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible or underground instrument and control (I&C) cables that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) I&C cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long-term wetting or submergence over a continuous period), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This is a condition monitoring program. However, this AMP includes periodic actions to prevent inaccessible I&C cables from being exposed to significant moisture. Periodic actions taken to mitigate I&C cable exposure to significant moisture include inspection for water accumulation in cable manholes, vaults, conduits, and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain or flooding. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults, is effective in preventing inaccessible cable exposure to significant moisture.

In addition to inspecting for water accumulation, I&C cables accessible from manholes, vaults, or other underground raceways are periodically visually inspected for cable jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the instrumentation and control cable electrical insulation. Inspection frequencies are adjusted based on inspection results, including site-specific OE. The visual inspection of I&C cables occurs at least once every six years and may be coordinated with the periodic inspection for water accumulation. Inaccessible and underground I&C cables found to be exposed to significant moisture are evaluated to determine whether testing is required. If required, initial testing is performed once by utilizing sampling to determine the condition of the electrical insulation. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. One or more tests may be required due to cable type, application, and electrical insulation to determine the age degradation of the cable. Inaccessible and underground I&C cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test. The need for additional tests and inspections is determined by the test/inspection results, as well as industry and site-specific OE.

Testing of installed inservice inaccessible and underground I&C cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, construction, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible I&C cables when testing is required in this AMP.

17.2.2.42 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements

The PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible or underground low-voltage ac and dc power cables (i.e., typical operating voltage of less than 1,000 V, but no greater than 2 kV) that are not subject to the requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long-term wetting or submergence over a continuous period), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This is a condition monitoring program. However, this AMP also includes periodic actions to prevent inaccessible low-voltage cables from being exposed to significant moisture. Periodic actions taken to mitigate inaccessible low-voltage cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduits, and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain or flooding. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults, is effective in preventing inaccessible cable exposure to significant moisture.

In addition to inspecting for water accumulation, low-voltage power cables accessible from manholes, vaults, or other underground raceways are periodically visually inspected for jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the low-voltage power cable electrical insulation. Inspection frequencies are adjusted based on inspection results, including site-specific OE. The visual inspection of low-voltage power cables occurs at least once every six years and may be coordinated with the periodic inspection for water accumulation. Inaccessible and underground low-voltage power cables found to be exposed to significant moisture are evaluated to determine whether testing is required. If required, initial testing is performed once by utilizing sampling to determine the condition of the electrical insulation. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. One or more tests may be required due to cable type, application, and electrical insulation to determine the age degradation of the cable. Inaccessible and underground low-voltage power cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test. The need for additional tests and inspections is determined by the test/inspection results, as well as industry and site-specific OE.

Testing of installed inservice inaccessible and underground low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or instrumentation and control cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is required in this AMP.

17.2.2.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements

The PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the EQ requirements of 10 CFR 50.49 and susceptible to age-related degradation resulting in increased resistance are maintained consistent with the CLB through the SPEO. This AMP applies to electrical connections within the scope of SLR and manages increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation of the metallic portions of electrical cable connections within the scope of SLR. This program does not apply to the high-voltage (> 35 kV) switchyard connections.

This AMP is a condition monitoring program that consists of a one-time test on a representative sample of each type of non-EQ electrical connections prior to the SPEO to confirm the absence of age-related degradation. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. The results are evaluated to determine the need for subsequent testing on a 10-year basis. The following factors are considered for sampling: voltage level (medium- and low-voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise, a technical justification of the methodology and sample size used for selecting the components under testing is documented.

As an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of the insulation materials may be used to detect aging effects and surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. The basis for performing only the alternative periodic visual inspection to monitor age-related degradation of cable connections is documented. If this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO with subsequent inspections performed at least once every five years thereafter.

17.2.2.44 High-Voltage Insulators

The PTN High-Voltage Insulators AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of high-voltage insulators within the scope of SLR are maintained consistent with the CLB through the SPEO. This AMP was developed specifically to age manage high-voltage insulators susceptible to aging degradation due to local environmental conditions. Periodic visual inspections along with periodic insulator coating and cleaning are performed to manage high-voltage insulator aging effects throughout the SPEO.

The scope of this AMP is limited to the high-voltage insulators in the power path utilized for restoration of off-site power following a Station Blackout event. This is a condition monitoring program. The high-voltage insulators within the scope of this AMP are visually inspected to detect reduced insulation resistance aging effects, including cracks, foreign debris, salt, dust, and industrial effluent contamination. Metallic parts are visually inspected to detect loss of material due to mechanical wear or corrosion. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance.

17.2.3 Site-Specific Aging Management Programs

This section provides the UFSAR summary of the PTN single site-specific program credited for managing the effects of aging. This PTN site-specific program is associated with pressurizer surge line fatigue.

17.2.3.1 Pressurizer Surge Line Fatigue

The PTN Pressurizer Surge Line Fatigue AMP is an existing AMP that was formerly the PTN Pressurizer Surge Line Welds Inspection Program. This AMP for fatigue assessment is based on the approach documented in the ASME Code Section XI Rules for In-service Inspection of Nuclear Power Plant Components, Non-Mandatory Appendix L Operating Plant Fatigue Assessment. This AMP incorporates:

(1) TLAAs that consider fatigue design, and;

(2) An aging management inspection program that has been approved by the NRC.

The fatigue design of the pressurizer surge line is based on: 1) the original transient design limits and 2) reactor water environmental effects using the most recent data from laboratory simulation of the reactor coolant environment. To address the initial 40-year operating period, Idaho National Engineering Laboratories evaluated fatigue-sensitive component locations in plants designed by all four U.S. nuclear steam supply system (NSSS) vendors, as reported in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995. This evaluation included calculation of fatigue usage factors for critical fatigue sensitive component locations of early vintage Westinghouse PWRs, utilizing the interim fatigue curves provided in NUREG/CR-5999, "Interim Fatigue Design Curves for Carbon, Low-Alloy, and Austenitic Stainless Steels in LWR Environments," August 1993. The results were then utilized to scale up the PTN site-specific usage factors for the same locations to account for environmental effects.

Thus, the results are directly relevant to the design code used for PTN Unit 3 and Unit 4, and the transient cycles considered in the evaluation match or bound the PTN design. Fatigue monitoring by FPL will ensure that these limits are not exceeded. In this manner, the original transient design limits for fatigue are confirmed to remain valid for the current 40-year operating period, the initial 20-year PEO, and the 20-year SPEO of PTN Unit 3 and Unit 4.

FPL has previously inspected all surge line welds on both units during the fourth ISI interval, prior to entering the PEO. The results of these inspections were utilized to assess fatigue of the surge lines. In addition to these inspections, environmentally assisted fatigue of the surge lines welds is addressed using the following approach:

(1) FPL elected to manage the effects of environmentally assisted fatigue of the pressurizer surge line welds by an aging management inspection program approved by the NRC.

(2) The aging management of the surge line is accomplished by a combination of flaw tolerance analysis and ISI. The aging effect managed with these inspections is cracking due to environmentally assisted fatigue. The technical justification and inspection frequency are supported by the flaw tolerance analysis based on the methodology noted in ASME Section XI, Nonmandatory Appendix L, "Operating Plant Fatigue Assessment." Based on postulated flaw tolerance analysis, and using the guidelines of ASME Code Section XI, Appendix L, Table L-3420-1, the periodic inspection schedule is determined to be 10 years.

(3) All pressurizer surge line welds listed in scope of the AMP is examined in accordance with ASME Section XI, IWB for Class 1 welds. Inservice examinations for the surge line welds include both surface and volumetric examinations. In each 10-year ISI interval during the SPEO, all surge line welds are inspected in accordance with the PTN ISI AMPs under Augmented and other programs.

17.3 TIME-LIMITED AGING ANALYSIS

With respect to plant TLAAs, 10 CFR 54.21(c) requires 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.*

This section discusses the evaluation results for each of the site-specific TLAAs performed for SLR. The evaluations have demonstrated that the analyses remain valid for the SPEO; that the analyses have been projected to the end of the SPEO; or that the effects of aging on the intended function(s) will be adequately managed for the SPEO. The TLAAs, as defined in 10 CFR 54.3, are listed in Section 17.3.1 through, and including, Section 17.3.7.6 and are evaluated per the requirements of 10 CFR 54.21(c).

17.3.1 Identification of Time-Limited Aging Analyses Exemptions

10 CFR 54.21(c)(2) states the following with respect to TLAA exemptions:

> *A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.*

A search of docketed licensing correspondence, the operating license, and the UFSAR was performed to identify the active exemptions currently in effect pursuant to 10 CFR 50.12. These exemptions were then reviewed to determine whether the exemption was based on a TLAA. No 10 CFR 50.12 exemptions involving a TLAA, as defined in 10 CFR 54.3, were identified for PTN Units 3 and 4. This addresses the 10 CFR 54.21(c)(2) exemptions list requirement.

17.3.2 Reactor Vessel Neutron Embrittlement

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, P T limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The PTN Reactor Vessel Material Surveillance AMP is described in Section 17.2.2.19.

The ferritic materials of the reactor vessel are subject to embrittlement due to high energy (E > 1.0 MeV) neutron exposure. Neutron embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). This group of TLAAs concerns the effect of IE on the belt-line regions of the PTN Units 3 and 4 reactor vessels, and how this mechanism affects analyses that provide operating limits or address regulatory requirements.

Neutron fluence is used to calculate parameters for embrittlement analyses that are part of the CLB and support safety determinations, and since these analyses are calculated based on plant life, they have been identified as TLAAs, as defined in 10 CFR 54.21(c). Therefore, the following TLAAs were evaluated for the increased neutron fluence associated with 80 years of operations:

- Neutron fluence projections (Section 17.3.2.1)
- Pressurized thermal shock (PTS) (Section 17.3.2.2)
- Upper-shelf energy (USE) (Section 17.3.2.3)
- Adjusted reference temperature (Section 17.3.2.4)
- Pressure-temperature (P-T) limits and low temperature overpressure setpoints (Section 17.3.2.5)

17.3.2.1 Neutron Fluence Projections

The fluence projections used as inputs to the current 60-year neutron embrittlement analyses were developed using discrete ordinates transport fluence methodology. At the time the projections were prepared, 48 effective full power years (EFPY) was considered to represent the amount of power to be generated over 60 years of plant operation, assuming a 60-year average capacity factor of 80 percent.

Updated fluence projections were developed for 80 years of plant operation, based upon 72 EFPY for use as inputs to updated neutron embrittlement analyses for the SPEO. They were also used to determine whether any additional materials will be exposed to fluence greater than 1.0×10^{17} n/cm^2 (E > 1.0 MeV) through the SPEO, which would be in the extended beltline. The 72 EFPY fluence projections were developed using methodologies that follow the guidance of NRC RG 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” These methodologies have been approved by the NRC and are described in detail in WCAP-14040-A and WCAP-16083-NP-A. The 72 EFPY fluence projections have been determined for reactor vessel beltline and extended beltline materials, which include all reactor vessel forgings and welds that are predicted to be exposed to 1.0×10^{17} neutrons/cm^2 (n/cm^2) or more during 80 years of operation. Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

Additionally, the PTN Neutron Fluence Monitoring AMP ensures the continued validity and adequacy of projected neutron fluence analyses and related neutron fluence-based TLAAs as described in Section 17.2.1.2.

17.3.2.2 Pressurized Thermal Shock

The requirements in 10 CFR 50.61 provide rules for protection against PTS events for PWRs. Licensees are required to perform an assessment of the projected values of the PTS reference temperature (RT_{PTS}), whenever a significant change occurs in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility. Section 10 CFR 50.61(b)(2) establishes screening criteria for RT_{PTS} at 270°F for plates, forgings, and axial welds, and 300°F for circumferential welds. The PTS analysis has been determined to be a TLAA. For PWRs, 10 CFR 50.61 requires the reference temperature RT_{PTS} for RPV beltline materials to be less than the PTS screening criteria at the expiration date of the operating license unless otherwise approved by the NRC. The reference temperature has been determined to be less than the PTS screening criteria at the end of SPEO, unless alternate requirements have been invoked in accordance with 10 CFR 50.61(b) and approved by the NRC.

The methods for calculating RT_{PTS} values are given in 10 CFR 50.61 and are consistent with the methods in NRC RG 1.99, "Radiation Embrittlement of Reactor Vessel Materials," with exception that PTN Units 3 and 4 received the following exemptions from Appendix G to 10 CFR Part 50 and 10 CFR 50.61.

The exemption from Appendix G to 10 CFR Part 50 is to replace the required use of the existing Charpy V-notch and drop-weight-based methodology with the use of an alternate methodology described in the Framatome ANP Topical Reports BAW-2308, Revisions 1-A and 2-A, “Initial RT_{NDT} of Linde 80 Weld Materials,” that incorporates the use of fracture toughness test data for evaluating the integrity of the Linde 80 weld materials present in the PTN Units 3 and 4 RPV beltline regions. The alternate methodology employs direct fracture toughness testing per the Master Curve methodology based on use of ASTM Standard Method E 1921 (1997 and 2002 editions) and ASME Code Case N-629. The exemption is required since Appendix G to 10 CFR Part 50 requires that for the pre-service or unirradiated condition, the nil-ductility reference temperature (RT_{NDT}) be evaluated by Charpy V-notch impact tests and drop weight tests according to the procedures in the ASME Code, Section III, Paragraph NB-2331.

The exemption from 10 CFR 50.61 is to use an alternate methodology described in the Framatome Advanced Nuclear Power Topical Report, BAW-2308, Revisions 1-A and 2-A, “Initial RT_{NDT} of Linde 80 Weld Materials.” BAW-2308 allows the use of direct fracture toughness test data for evaluating the integrity of the Linde 80 weld materials present in the PTN Units 3 and 4 reactor vessels beltline regions, based on the use of ASTM E 1921 (1997 and 2002 editions) and ASME Code Case N-629. The exemption is required because the methodology for evaluating reactor vessels material fracture toughness in 10 CFR 50.61 requires that the pre-service or unirradiated condition be evaluated using Charpy V-notch impact tests and drop weight tests according to the procedures in the ASME Code, Section III, Paragraph NB-2331.

An exemption from a portion of the requirements of Appendix G to 10 CFR Part 50 and 10 CFR 50.61 is required to allow for an alternative methodology, that is based on using of fracture toughness test data, to determine the initial, unirradiated properties that are used for evaluating the integrity of the PTN reactor vessels' circumferential beltline welds. This exemption addresses only those parts of the regulations (i.e., 10 CFR 50.61 and 10 CFR Part 50, Appendix G) that discuss the definition or use of unirradiated nil-ductility reference temperature ($RT_{NDT(U)}$), and its associated uncertainty, σ_{Δ}. All other requirements of 10 CFR 50.61 and 10 CFR Part 50, Appendix G, are unchanged by this exemption.

These methods were used to calculate the RT_{PTS} for the PTN reactor vessel limiting materials at the end of the SPEO, 72 EFPY. The calculated RT_{PTS} values at 72 EFPY for the PTN reactor vessels are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells, and less than 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the PTN reactor vessels during the SPEO. Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.2.3 Upper Shelf Energy

Appendix G of 10 CFR Part 50, Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy USE of no less than 75 ft-lb initially and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

Per NRC RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," the Charpy USE should be assumed to decrease as a function of fluence according to RG 1.99, Figure 2, when credible surveillance data is not available. If credible surveillance data is available, the decrease in USE may be obtained by plotting the reduced plant surveillance data on Figure 2 of RG 1.99 and fitting the data with a line drawn parallel to the existing lines as the upper bound of all of the data.

All PTN Unit 3 reactor vessel materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for the IS-to-LS and US-to-IS circumferential welds.

All PTN Unit 4 reactor vessel materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for the IS-to-LS and US-to-IS circumferential welds.

For the PTN Units 3 and 4 reactor vessel materials that do not maintain a USE value above 50 ft-lbs through 72 EFPY, an EMA was performed. The analysis was performed on the circumferential weld with the lowest projected USE value, which was the IS-to-LS circumferential weld for both Units. The analysis concludes that the PTN Units 3 and 4 IS-to-LS circumferential welds satisfy the acceptance criteria of Appendix K of Section XI of the ASME Code for projected low USE at 72 EFPY. Since the IS-to-LS circumferential weld is the bounding material for each

Unit, all PTN Units 3 and 4 reactor vessel materials have been demonstrated to meet the requirements of 10 CFR 50, Appendix G, with regards to low USE.

The USE values for the PTN reactor vessel beltline and extended beltline materials are projected to remain above 50 ft-lb at 72 EFPY of neutron exposure through the SPEO. The projections demonstrated that the requirements of 10 CFR Part 50, Appendix G, will continue to be met through the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.2.4 Adjusted Reference Temperature

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. NRC RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” provides the methodology for determining the ART of the limiting material. The initial nil-ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the ASME Code Section III, Paragraph NB-2331. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR Part 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) means that higher temperatures are required for the material to continue to act in a ductile manner. The ART is defined as:

Initial RT_{NDT} + (ΔRT_{NDT}) + Margin

Since the ΔRT_{NDT} value is a function of 48 EFPY fluence, associated with the 60-year licensed operating period, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

The 72 EFPY fluence values were determined for PTN Units 3 and 4 for the RPV beltline and extended beltline components. These 72 EFPY fluence values, postulated flaw depth at a location one quarter of the vessel wall thickness from the clad/base metal interface (¼T), were used to compute ART values for the PTN RPV beltline and extended beltline materials in accordance with NRC RG 1.99, Revision 2, requirements. The projections demonstrate that the ART values in the limiting material for each unit will remain below the NRC RG 1.99, Revision 2, Section 3, acceptance criteria of 200°F through the SPEO. Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.2.5 Pressure-Temperature Limits and Low Temperature Overpressure Setpoints

Appendix G of 10 CFR Part 50 requires that the reactor vessel be maintained within established P-T limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor vessel is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated reactor vessel fluence.

The current P-T limits are based upon 48 EFPY fluence projections that were considered to represent the amount of power to be generated over 60 years of plant operation, assuming a 60-year average capacity factor of 80 percent. Since the P-T limits are currently based upon a 60-year assumption regarding capacity factor, the P-T limits satisfy the criteria of 10 CFR 54.3(a) and have been identified as TLAAs.

In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the SPEO need not be submitted as part of the SLRA since P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits that are located in the PTN Technical Specifications (TS). The 10 CFR 50.90 process will ensure that the P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current period of operation.

The current PTN Units 3 and 4 heatup and cooldown curves are calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the reactor vessel for 48 EFPY based on extended power uprate (EPU) fluence. The PTN Units 3 and 4 reactor vessel P-T limit curves are contained in plant TS Section 3/4.4.9. Prior to exceeding 48 EFPY, new P-T limit curves will be generated to cover plant operation beyond 48 EFPY. The P-T limit curves will be developed using NRC-approved analytical methods. The analysis of the P-T curves will consider locations outside of the beltline, such as nozzles, penetrations and other discontinuities, to determine if more restrictive P-T limits are required than would be determined by considering only the reactor vessel beltline materials. Additionally, PTN TS 3/4.4.9.3 specify the power-operated relief valve (PORV) lift settings to mitigate the consequences of low temperature overpressure events. Each time the P-T limit curves are revised, the LTOP PORV setpoints must be reevaluated. Therefore, LTOP limits are considered part of the calculation of P-T curves.

The Reactor Vessel Material Surveillance AMP will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the current terms of applicability for PTN Units 3 and 4. The P-T limit curves and LTOPs PORV setpoints will be updated and a plant TS change request will be submitted for approval prior to exceeding the current 48 EFPY limits. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

17.3.3 Metal Fatigue

Fatigue is an age-related degradation mechanism caused by cyclic stressing of a component by either mechanical or thermal stresses. The thermal and mechanical fatigue analyses of plant mechanical components have been identified as TLAAs for PTN. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the PTN UFSAR. Fatigue analyses are considered TLAAs for Class 1 and non-Class 1 mechanical components requiring evaluation for the SPEO in accordance with 10 CFR 54.21(c). Evaluation of these TLAAs per 10 CFR 54.21(c)(1) determines whether:

i. The analyses remain valid for the SPEO;
ii. The analyses have been projected to the end of the SPEO, or;
iii. The effects of aging on the intended function(s) will be adequately managed for the SPEO.

The following evaluations are documented in the following sections:

- Class 1 component fatigue analyses are in Section 17.3.3.1.
- Fatigue analysis of non-Class 1 mechanical components is in Section 17.3.3.2.
- Environmentally assisted fatigue analysis is in Section 17.3.3.3.
- Reactor vessel underclad cracking analysis is in Section 17.3.3.4.
- RCP flywheel analysis is in Section 17.3.3.5.

17.3.3.1 ASME Boiler and Pressure Vessel Code, Section III, Class 1 Components

The reactor vessels, RVI, pressurizers, steam generators, RCPs, and pressurizer surge lines have been designed in accordance with the requirements of the ASME Code Section III, Class 1. The ASME Code Section III, Class 1 requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. Fatigue analyses were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature, pressure, and seismic loading cycles. These ASME Code Section III, Class 1, fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients described in the 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, pressure, and flow. The fatigue analyses were required to demonstrate that the CUF will not exceed the design allowable limit of 1.0 when the equipment is exposed to all of the postulated transients. Since the calculation of fatigue usage factors is part of the CLB and is used to support safety determinations, and since the number of occurrences of each transient type was based upon 60-year assumptions, these Class 1 fatigue analyses have been identified as TLAAs requiring evaluation for the SPEO.

The ASME Code Section III, Class 1, allowable stress calculations remain valid for the SPEO. The results demonstrate that the number of assumed thermal cycles will not be exceeded in 80 years of plant operation. PTN will monitor transient cycles using the PTN Fatigue Monitoring AMP and assure that the corrective action specified in the program is taken if any of the actual cycles approach their analyzed numbers. However, not all the components can pass the environmentally assisted fatigue analysis using the original number of design transients, and the containment liner has taken credit for restricting the number of RCS heatup and cooldown events. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

17.3.3.2 ANSI B31.1 and ASME Boiler and Pressure Vessel Code, Section III, Class 3 Piping

The RCS primary loop piping and balance-of-plant piping are designed to the requirements of ANSI B31.1, Power Piping. The exceptions are the PTN Units 3 and 4 pressurizer surge lines and the PTN Unit 4 EDG safety-related piping. The pressurizer surge lines have been designed to the requirements of ASME Code Section III, Class 1. The Unit 4 EDG safety-related piping has been designed to the requirements of ASME Code Section III, Class 3, which is essentially the same as ANSI B31.1 design requirements. The evaluation of the Unit 4 EDG safety-related piping fatigue is, therefore, included in this section.

Piping and components designed in accordance with ANSI B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in a simplified manner in the design process. These codes first require prediction of the overall number of thermal and pressure cycles expected during the 80-year lifetime of these components. Then a stress range reduction factor is determined for that number of cycles using a table from the applicable design code. If the total number of cycles is 7,000 or less, the stress range reduction factor of 1.0 is applied that would not reduce the allowable stress value. These are considered to be implicit fatigue analyses since they are based upon cycles anticipated for the life of the component, and are, therefore, TLAAs requiring evaluation for the SPEO.

Design requirements in ANSI B31.1 assume a stress range reduction factor to provide conservatism in the piping design to account for fatigue due to thermal cyclic operation. The cyclic qualification of the piping is based on the number of equivalent full-temperature cycles. The stress range reduction factor is 1.0 provided the number of anticipated cycles is limited to 7,000 equivalent full-temperature cycles. A review of the ANSI B31.1 piping within the scope of SLR was performed in order to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Under current plant operating practices, piping systems within the scope of SLR are only occasionally subject to cyclic operation. Typically, systems are subject to continuous steady-state operation and vary operating temperatures only during plant heatup and cooldown, during plant transients, or during periodic testing. From the EPRI TR-104534, Volume 2, Section 4, piping systems subject to thermal fatigue due to temperature cycling are described as follows:

> *For initial screening, systems in which the fluid temperature can vary more than 200°F in austenitic steel components and more than 150°F in carbon and low alloy steel components are potentially of concern for fatigue due to thermal transients. Thus, carbon steel systems or portions of systems with operating temperatures less than 220°F and stainless steel systems or portions of systems with operating temperatures less than 270°F may generally be excluded from such concerns, since room temperature represents a practical minimum exposure temperature for most plant systems.*

Conservatively, based on this assessment, any system or portions of systems with operating temperatures less than 220°F were conservatively excluded from further consideration. Once a system is established to operate at a temperature above 220°F, the next step is to determine the system operating characteristics. For example, it is determined when the system is in heatup and cooldown mode, such as during testing reactor trips, sampling or swapping trains. The operating characteristics of a pipe segment are established by reviewing system operations and conducting interviews with appropriate operations personnel. With these operating characteristics defined, a determination can be made regarding whether a system is expected to exceed 7,000 full temperature cycles in 80 years of operation. In order to exceed 7,000 cycles, a system would be required to heatup and cooldown approximately once every four days. Systems that may exceed 7,000 cycles in 80 years were evaluated further.

The ASME Code Section III, Class 3, and ANSI B31.1 allowable stress calculations remain valid for the SPEO. The results demonstrate that the number of assumed thermal cycles will not be exceeded in 80 years of plant operation. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

17.3.3.3 Environmentally Assisted Fatigue

NUREG-2192 provides a recommendation for evaluating the effects of the reactor water environment on the fatigue life of ASME Code Section III, Class 1, components that contact reactor coolant to support closure of Generic Safety Issue (GSI)-190. One method acceptable to the NRC for satisfying this recommendation is to assess the impact of the reactor coolant environment on a sample of critical components. These critical components should include those selected in NUREG/CR- 6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.”

This sample of components can be evaluated by applying environmental life correction factors to the existing ASME Code fatigue analyses. Demonstrating that these components, and other site-specific locations that are more limiting, have an environmentally adjusted CUF less than or equal to the design limit of 1.0 is an acceptable option for managing environmentally assisted metal fatigue for the reactor coolant pressure boundary. Since the calculation of fatigue usage factors is part of the CLB and is used to support safety determinations, and since the number of occurrences of each transient type was based upon 60-year assumptions, these Class 1 fatigue analyses have been identified as TLAAs requiring evaluation for the SPEO.

For the reactor vessels, RVI, pressurizers, steam generators, and RCPs, the environmentally assisted fatigue analysis remains valid for the SPEO. PTN will monitor transient cycles using the PTN Fatigue Monitoring AMP and assure that the corrective action specified in the program is taken if any of the actual cycles approach their analyzed numbers. These components are dispositioned in accordance with 10 CFR 54.21 (c)(1)(iii).

For the pressurizer surge line, PTN will manage the effects of aging due to fatigue on the pressurizer surge line by implementing volumetric examination of the welds using the Pressurizer Surge Line Fatigue Program (Section 17.2.3.1) in accordance with 10 CFR 54.21(c)(1)(iii).

17.3.3.4 Reactor Vessel Underclad Cracking

In early 1971, an anomaly identified as grain boundary separation, perpendicular to the direction of the cladding weld overlay, was identified at another nuclear plant in the heat-affected zone of reactor vessel base metal. Reactor vessel underclad cracking involves cracks in base metal forgings immediately beneath austenitic SS cladding, which are created as a result of the weld-deposited cladding process. Westinghouse performed an analysis of flaw growth associated with underclad cracking in 1971, and concluded that reactor vessel integrity could be assured for the entire 40-year original plant license term. Since the reactor vessel underclad cracking is part of the CLB and is used to support safety determinations, and since the probability of failure was based upon operating history assumptions, this cracking analysis has been identified as a TLAA requiring evaluation for the SPEO.

Flaw indications indicative of underclad cracks have been evaluated in accordance with the acceptance criteria of the ASME Code Section XI at other nuclear plants. Such indications have been found during pre-service and ISI of plants considered to have cladding conditions, which are suspect with respect to underclad cracking. These flaw indications have been dispositioned as being acceptable for further service without repair or detailed evaluation, because they meet the conservative requirements of the ASME Code Section XI, Paragraph IWB-3500.

Fracture evaluations have also been performed to evaluate underclad cracks, and the results have always been that the flaws are acceptable. A number of field examples, which have involved cladding cracks and exposure of the base metal due to cladding removal, were summarized. In several cases, the cladding cracks have been suspected to extend into the base metal, and have been analyzed as such. In these cases, the cracks were suspected to be exposed to the water environment, and successive monitoring inspections were conducted on the area of concern. No changes were found due to propagation or further deterioration of any type. The NRC then allowed the surveillance to be discontinued.

Finally, underclad cracks found during pre-service and ISI have been evaluated in accordance with the acceptance criteria of the ASME Code Section XI. The observed underclad cracks are very shallow, confined in depth to less than 0.295 inch and have lengths up to 2.0 inches. The fatigue crack growth assessment for these small cracks shows very little extension over 80 years, even if they were exposed to the reactor water and with crack tip pressure of 2,500 psi. For the worst-case scenario, a 0.30-inch-deep continuous axial flaw in the beltline region would grow to 0.43 inch after 80 years. The minimum allowable axial flaw size for normal, upset and test conditions is 0.67 inch, and for emergency and faulted conditions, it is 1.25 inches. Since the allowable flaw depths far exceed the maximum flaw depth after 80 years of fatigue crack growth, underclad cracks of any shape are acceptable for service for 80 years, regardless of the size or orientation of the flaws. Therefore, per PWROG-17031-NP, Rev. 0, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants,” it may be concluded that underclad cracks are of no concern relative to structural integrity of the reactor vessel for a period of 80 years.

Based on the above information, the analysis associated with reactor vessel underclad crack growth has been projected to the end of the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.3.5 Reactor Coolant Pump Flywheel

NUREG-2191 identifies “Fatigue analysis of the reactor coolant pump flywheel” as a potential site-specific TLAA. Fatigue in the flywheels is a recognized and analyzed aging effect. Due to industry OE, the possibility of RCP overspeed or RCP vibration prompted concerns regarding the potential effects of missiles that might result from the failure of the RCP motor flywheel, including damage to RCP seals or other pressure boundary components.

Since the RCP flywheel probability of failure is part of the CLB and is used to support safety determinations, and since the probability of failure was based upon 60-year assumptions, these Class 1 fatigue analyses have been identified as TLAAs requiring evaluation for the SPEO.

During normal operation, the RCP flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions that may result in overspeed of the RCP increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway. An evaluation of the probability of failure during the SPEO was performed, and it demonstrated that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over an 80-year service life. Based on the above information, the RCP flywheel fatigue analysis remains valid for the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.4 Environmental Qualification of Electrical Equipment

Thermal, radiation, and cyclical aging analyses of plant electrical and instrumentation components, developed to meet 10 CFR 50.49 requirements, have been identified as TLAAs. The NRC has established EQ requirements in 10 CFR 50.49 and 10 CFR Part 50, Appendix A, Criterion 4. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a LOCA, HELB, or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations for electrical components in the EQ Program that specify a qualification of at least 60 years have been identified as TLAAs for license renewal because the criteria contained in 10 CFR 54.3 are met.

The PTN Environmental Qualification of Electric Equipment AMP (Section 17.2.1.4) meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of components within the scope of the PTN Environmental Qualification of

Electric Equipment AMP, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected during their service life.

10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e)(5) also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions. 10 CFR 50.49(k) and (l) permit different qualification criteria to apply based on plant and component vintage. Supplemental EQ regulatory guidance for compliance with these different qualification criteria is provided in the Division of Operating Reactors (DOR) Guidelines, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment," and NRC RG 1.89, Revision 1, "Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants."

The PTN Environmental Qualification of Electric Equipment AMP will manage the effects of aging effects for the components associated with the EQ TLAA. This AMP implements the requirements of 10 CFR 50.49 (as further defined and clarified by NUREG-0588 and RG 1.89, Rev. 1). Component aging evaluations are reanalyzed on a routine basis to extend the qualifications of components as part of the PTN Environmental Qualification of Electric Equipment AMP. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The methodology of the PTN Environmental Qualification of Electric Equipment AMP is further described in Section 17.2.1.4.

Under the PTN Environmental Qualification of Electric Equipment AMP, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or re-qualify the component if the reanalysis is unsuccessful.

The effects of aging on the intended function(s) will be adequately managed for the SPEO. The PTN Environmental Qualification of Electric Equipment AMP has been demonstrated to be capable of programmatically managing the qualified lives of the electrical and instrumentation components falling within the scope of the program for SLR. The PTN Environmental Qualification of Electric Equipment AMP provides reasonable assurance that the aging effects will be managed and that EQ components will continue to perform their intended functions for the SPEO. Therefore, this result meets the requirements of 10 CFR 54.21(c)(1)(iii).

17.3.5 Concrete Containment Unbonded Tendon Prestress

The PTN Units 3 and 4 containment buildings are prestressed, post-tensioned, reinforced-concrete structures composed of vertical cylinder walls and a shallow dome, supported on a conventionally reinforced concrete base slab. The cylinder walls are provided with vertical tendons and horizontal hoop tendons. The dome is provided with three groups of tendons oriented 120-degrees apart. Over time, the containment prestressing forces decrease due to relaxation of the steel tendons and due to creep and shrinkage of the concrete.

The prestress force of containment tendons decreases over time as a result of seating of anchorage losses, elastic shortening of concrete, creep of concrete, shrinkage of concrete, relaxation of prestressing steel, and friction losses. At the time of initial licensing, the magnitude of the prestress losses throughout the life of the plant was predicted, and the estimated final effective preload at the end of 40 years was calculated for each tendon type. The final effective preload was then compared with the minimum required preload to confirm the adequacy of the design. The estimated final effective prestressing force at the end of plant life was previously extended to 60 years during the initial license renewal process.

Examinations performed as part of the PTN Concrete Containment Unbonded Tendon Prestress AMP (Section 17.2.1.3) and the PTN ASME Section XI, Subsection IWL, AMP (Section 17.2.2.31), in accordance with ASME Section XI, Subsection IWL, requirements, include the measurement of the prestressing force values from multiple tendons within each tendon group (vertical, hoop, and dome) during periodic examinations. These measurements are compared to MRVs and predicted lower limit force values to verify that the containment structure is performing its intended function, as well as to compare the actual loss of prestress rate to the predicted rate. Trend lines of the individual tendon prestressing force values for each tendon group are developed to predict future tendon prestressing force values to ensure the containment structure will continue to perform its intended function.

Trend lines calculated, based on the most recent tendon surveillances for all three tendons groups at PTN Units 3 and 4, have been extended from 60 years to 80 years. In all cases, the trend lines indicate the prestressing forces will remain above the MRVs through the end of the SPEO. The implementation of the PTN Concrete Containment Unbonded Tendon Prestress AMP (Section 17.2.1.3) and the PTN ASME Section XI, Subsection IWL, AMP (Section 17.2.2.31) will provide reasonable assurance that the loss of containment tendon unbonded prestress will be adequately managed so that the intended functions are maintained during the SPEO. Since the concrete containment unbonded tendon prestress analysis has been projected to the end of the SPEO, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

17.3.6 Containment Liner Plate and Penetrations Fatigue Analysis

The PTN prestressed concrete containment structures are designed to contain the radioactive material that would be released in the unlikely event of design basis accidents. Each containment structure includes a liner attached to the entire inside surface that provides a leak-tight membrane. The design specification requires the liner to be analyzed for the effects of cyclic loading. Since the current design analysis for the containment liner is based upon 60-year design inputs, it has been identified as a TLAA requiring evaluation for the SPEO.

The interior surface of each containment is lined with welded steel plate to provide an essentially leak-tight barrier. Design criteria are applied to the liner to assure that the specified allowed leak rate is not exceeded under the design basis accident conditions. Prior to SLR, the following fatigue loads were described in UFSAR Appendix 5B, Section B.2.1, and were considered in the design of the liner plates. The following fatigue loads are considered a TLAA for the purpose of SLR:

(1) Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 60 for the plant life of 60 years.

(2) Thermal cycling due to containment interior temperature varying during the heatup and cooldown of the RCS. The number of cycles for this loading is assumed to be 500.

(3) Thermal cycling due to the maximum hypothetical accident will be assumed to be one.

(4) Thermal load cycles in the piping system are somewhat isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Code Section III fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the unit life.

Each of the four previous items has been evaluated for the SPEO as follows:

(1) For item (1), the number of thermal cycles due to annual outdoor temperature variations was increased from 60 to 80 for the SPEO. The effect of this increase is insignificant in comparison to the assumed 500 thermal cycles due to containment interior temperature varying during heatup and cooldown of the RCS. The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 RCS allowable design heatup and cooldown cycles, which is sufficient margin to accommodate the additional 20 cycles of annual outdoor temperature variation. Therefore, this loading condition is considered valid for the SPEO as it is enveloped by item (2).

(2) For item (2), the assumed 500 thermal cycles was evaluated based on the more limiting heatup and cooldown design cycles (transients) for the RCS. The RCS was designed to withstand 200 heatup and cooldown thermal cycles. The SLRA evaluation determined that the originally projected number of maximum RCS design cycles is conservative enough to envelop the projected cycles for the PEO. Therefore, the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is considered valid for the SPEO.

(3) For item (3), the assumed value for thermal cycling due to the maximum hypothetical accident remains valid. No maximum hypothetical accident has occurred and none is expected; therefore, this assumption is considered valid for the SPEO.

(4) For item (4), the design of the containment penetrations has been reviewed. The design meets the general requirements of the 1965 Edition of ASME Code Section III. The main steam piping, feedwater piping, blowdown piping, and letdown piping are the only piping penetrating the containment wall and liner plate that contribute significant thermal loading on the liner plate. The projected number of actual operating cycles for these piping systems through 80 years of operation was determined to be less than the original design limits.

The effects of aging on the intended function(s) of the liner will be adequately managed for the SPEO by the PTN Fatigue Monitoring AMP (Section 17.2.1.1), which monitors transient cycles to ensure the transient limits are not exceeded during the SPEO, validating the assumptions used in these evaluations. No penetration TLAAs were identified. The analyses associated with the containment liner plate have been evaluated and determined to remain valid for the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

17.3.7 Other Site-Specific TLAAs

17.3.7.1 Bottom-Mounted Instrumentation Thimble Tube Wear

As discussed in NRC IN 87-44, Supplement 1, "Thimble Tube Thinning in Westinghouse Reactors," thimble tubes have experienced thinning as a result of flow-induced vibration. Thimble tube wear results in degradation of the RCS pressure boundary and could potentially create a non-isolable leak of reactor coolant. Since flow-induced vibration continues throughout the plant life, thimble tube wear is considered a TLAA. The NRC staff requested that licensees perform the actions described in NRC Bulletin No. 88-09, "Thimble Tube Thinning in Westinghouse Reactors." In response to this bulletin, PTN established a program for inspection and assessment of thimble tube thinning. PTN commitments to the NRC for two eddy current inspections of the thimble tubes for each unit were completed in May 1990 for Unit 4, and in December 1992 for Unit 3. The results demonstrated that the thimble tubes were acceptable for operation and that no appreciable thinning had occurred between the two inspections. Based on the results of the inspections and the flaw analyses performed, only the Unit 3 thimble tube N-05 required further evaluation.

The subsequent inspection on Unit 3 thimble tube N-05 was performed in October 2004. The results of this inspection indicated that N-05 was within the acceptance criteria for thimble tube wall thinning, which is less than 70 percent wall loss; however, thimble tube wear had continued. In 2009, Unit 3 thimble tube N-05 was replaced. Based on the above, the PTN Flux Thimble Tube Inspection AMP is an effective program for managing the aging effect of material loss due to fretting wear.

The PTN Flux Thimble Tube Inspection AMP (Section 17.2.2.24) provides an effective program to managing the aging effects of material loss due to fretting wear for the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

17.3.7.2 Emergency Containment Cooler Tube Wear

Emergency containment cooler tube wear was assessed for the operating term as flow rate through the emergency containment coolers could exceed the nominal design flow during certain plant conditions and cause wear of the coils. The wall thickness and wear rate determined in this assessment were projected for the initial PEO and is a TLAA for the SPEO.

The component cooling water (CCW) flow rate through the emergency containment coolers could exceed the nominal design flow during certain plant conditions. High flow rates can produce increased wear on the inside surface of the emergency containment cooler coils. The CCW flow rate through the emergency containment coolers could exceed the nominal design flow of 2,000 gpm during the injection phase of a LOCA or during the monthly operability test. Flow rates as high as 5,500 gpm have been experienced during the surveillance test.

This high flow rate can produce increased wear on the inside surface of the emergency containment cooler coils. This increased erosion wear rate has been predicted to be up to 0.5 mils/year due to flow-induced erosion with an additional impingement wear rate of 0.6 mils/year at those locations subject to impingement. This results in a wear rate in the range of 0.5 mils/year to 1.1 mils/year depending on coil tube location. This effect was evaluated, and the tube wall nominal thickness of 0.049 inches did not decrease below the minimum required wall thickness of 0.010 inches during the initial operating period. Since tube wear continues throughout the plant life, emergency containment cooler tube wear is considered a TLAA.

To ensure emergency containment cooler coil reliability, an inspection for minimum tube wall thickness was conducted in 2011 prior to the initial PEO. Results concluded that the calculated tube wear rates would be acceptable for the PEO. However, since cooler tube wall loss has been observed, an inspection of the emergency containment cooler coils to confirm updated tube wear rates would be acceptable for the revised 80-year plant life will be performed.

The PTN One-Time Inspection AMP will ensure that the aging effect of emergency containment cooler tube wear will be adequately managed for the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

17.3.7.3 Leak-Before-Break for Reactor Coolant System Piping

A site-specific Leak-Before-Break (LBB) analysis was performed for PTN Units 3 and 4 in 1994, as stated in WCAP-14237, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Turkey Point Units 3 and 4 Nuclear Power Plant," and approved by the June 23, 1995 letter from Richard P. Croteau (NRC) to J. H. Goldberg (FPL), “PTN Units 3 and 4 - Approval to Utilize Leak-Before-Break Methodology for Reactor Coolant System Piping.” The LBB analysis was performed to show that any potential leaks that develop in the RCS loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. The NRC safety evaluation concluded that the LBB analysis was consistent with the criteria in NUREG-1061, Volume 3, and NUREG-0800, Section 3.6.3; therefore, the analysis complied with 10 CFR 50, Appendix A, General Design Criterion 4.

The LBB analysis for PTN Units 3 and 4 was revised to address the initial PEO, utilizing criteria consistent with the original LBB analysis and was subsequently revised to address the EPU. Since the LBB analysis depends on the potential that a postulated crack would grow to unstable proportions during the plant life, which is dependent on the length of plant operation, the LBB analysis is a TLAA.

The aging effects that must be addressed for SPEO include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the RCS loop piping is embrittlement of the duplex ferritic CASS components. This effect results in a reduction in fracture toughness of the material.

The LBB analysis for PTN Units 3 and 4 was revised to address the SPEO utilizing criteria consistent with the original LBB analysis. Since the primary loop piping includes cast SS fittings, fully aged fracture toughness properties were determined for each heat of material. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which LBB crack stability evaluations were made. Through-wall flaw sizes were postulated at the critical locations that would cause leakage at a rate 10 times the leakage detection system capability. Including the requirement for margin of applied loads, large margins against flaw instability were demonstrated for the postulated flaw sizes.

For the SPEO, a site-specific fatigue crack growth analysis for PTN Units 3 and 4 for an 80-year plant life was performed. A design transient set that bounds the PTN design transients was utilized in the fatigue crack growth analysis, and it was determined that fatigue crack growth for the SPEO is negligible. The LBB analysis for the RCS primary loop piping has been projected to the end of the SPEO; therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.7.4 Leak-Before-Break Class 1 Auxiliary Piping

An LBB analysis of the Class 1 auxiliary lines was performed for the EPU, during the initial PEO, and it is valid for the current 60-year period of operation. Since the LBB analysis depends on the potential that a postulated crack would grow to unstable proportions during the plant life, which is dependent on the length of plant operation, the LBB analysis is a TLAA.

To demonstrate continued compliance during the SPEO, the analyses associated with Class 1 auxiliary line LBB were reevaluated by Structural Integrity Associates for 80 years. Since the

Class 1 auxiliary piping has been projected to the end of the SPEO, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.7.5 Code Case N-481 Reactor Coolant Pump Integrity Analysis

To support the EPU, Westinghouse performed an evaluation of the Code Case N-481 RCP integrity analysis to identify if it is acceptable for the PEO. The results of the evaluation concluded that the previous RCP integrity analysis conclusions documented in WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems," and WCAP-15355, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the PTN Units 3 and 4," for the RCP casings remain valid for the 60-year licensed operating period at EPU conditions. Based on these conclusions, no AMP beyond the examinations required in ASME Section XI is required to manage the thermal embrittlement for the RCP casings. Since the analysis depends on the potential that a postulated crack would grow to unstable proportions during the plant life, which is dependent on the length of plant operation, the analysis is a TLAA.

To demonstrate continued compliance during the SPEO, the analyses associated with the application of Code Case N-481 to the RCP casing during the SPEO was re-evaluated by PWROG-17033-NP, *Update for Subsequent License Renewal: WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems*."

The effects of aging on the intended function(s) will be adequately managed by the PTN ISI AMPs for the period of extended operation projected to the end of the SPEO. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

17.3.7.6 Crane Load Cycle Limit

A review of design specifications for cranes is within the scope of license renewal and has been performed. Crane design includes considerations for frequency of operation and expected size of loads, relative to their maximum load capacity. Based upon these considerations, cranes are given an expected maximum number of design cycles over their life, which also correlates to a number of cycles on structural members.

Since the maximum number of design load cycles over the current 60-year life of the cranes provide the basis for acceptability of the design for cyclic operation over the life of the cranes, these cyclic analyses are considered TLAAs. Therefore, the maximum number of design load cycles for the PEO was evaluated for the SPEO.

The load cycle limit for cranes was identified as a TLAA. At PTN Units 3 and 4, the following cranes are within the scope of SLR:

- Reactor building polar cranes
- Spent fuel cask cranes

- Intake structure bridge cranes (also called intake area gantry cranes or intake structure cranes)
- Turbine gantry cranes (also called turbine cranes)
- Charging pump monorails
- Safety injection pump monorails
- Main steam platform monorails
- Reactor cavity manipulator cranes (also called fuel handling manipulator cranes)
- Fuel transfer machines (only the portions that require aging management as determined by the OE report
- Spent fuel bridge cranes
- Fuel pool bulkhead monorails
- ICW valve pit rigging beam
- Turbine plant cooling water (TPCW) basket strainer monorail

Metal fatigue (fatigue stress) results from repeated loading. Routinely, a load or stress is applied and completely or partially removed or reversed repeatedly. This manner of loading is important if high stresses are repeated for a few cycles, or if lower stresses are repeated many times.

All Cranes except Spent Fuel Bridge Cranes

This evaluation is used to determine if a cyclic limit must be placed on the operational life of the subject cranes to ensure safe operation. Although the fatigue criterion in place during the manufacturing of the cranes is not explicitly addressed in Electrical Overhead Crane Institute (EOCI)-61, it can be concluded that proven analytical methods as a source of design input is credible. Since EOCI-61 does not explicitly address fatigue, a comparison was made with the fatigue provisions of the sixth edition of the AISC Manual of Steel Construction, which is the code of record for structural design, in order to determine the allowable number of cycles of loading that are inherent in the EOCI-61 criteria.

For up to 2,000,000 cycles of maximum load, Section 1.7.3 of the AISC Manual of Steel Construction requires that the allowable stresses be based on the use of A7 steel using Sections 1.5 and 1.6 of the specification. It also stipulates that these allowables be compared to the algebraic difference between the maximum computed stress and the minimum computed stress, but not be less than those required to support either the maximum or minimum computed stress in accordance with Sections 1.5 and 1.6.

The cranes covered by this calculation are configured so that the minimum computed stress is effectively zero. In other words, there is no stress reversal. Therefore, the maximum loading controls the design of the structural elements (max. stress).

Therefore, the cranes are acceptable for use of up to 2,000,000 cycles of maximum loads. For an 80-year period of operation, this equates to 68 cycles per day.

Spent Fuel Bridge Cranes

The spent fuel bridge cranes were replaced in 1990. Design of the spent fuel bridge cranes was in accordance with CMAA-70, with added seismic requirements.

Per the AISC Manual of Steel Construction, maximum stresses developed in the main structural elements and their connections are minimal relative to the strength and fatigue allowables. The only element with significant stress levels is the connection plate of the upper walkway to the side of the W10x33 column. The maximum stress in this element for loads, inclusive of the walkway, is approximately 20 ksi. If this stress is conservatively considered totally reversing, the resulting stress range is within the allowable tolerance for Service Class A Crane. Therefore, the cranes are acceptable for use of up to 200,000 cycles of maximum loads.

Since the spent fuel bridge cranes were installed in 1990 and the SPEO for PTN ends on 2053, the spent fuel bridge cranes will have operated for 63 years. For the SPEO, this equates to 8.6 cycles per day. This is far more cycles than these cranes experience.

The analyses associated with crane design, including fatigue, remain valid for the SPEO; therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

17.4 SUBSEQUENT LICENSE RENEWAL (SLR) COMMITMENTS LIST

The current license for PTN ends and the SPEO begins on the following dates:

- Unit 3: 07/19/2032 (01/19/2032 for AMP and enhancement implementation no later than 6 months prior to SPEO)
- Unit 4: 04/10/2033 (10/10/2032 for AMP and enhancement implementation no later than 6 months prior to SPEO)

Table 17-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
1	Fatigue Monitoring (17.2.1.1)	X.M1	Continue the existing PTN Fatigue Monitoring AMP, including enhancement to: a) Update the plant procedure to monitor chemistry parameters that provide inputs to F_{en} factors used in CUF_{en} calculations. b) Update the plant procedure to identify and require monitoring of the 80-year projected plant transients that are utilized as inputs to CUF_{en} calculations. c) Update the plant procedure to identify the corrective action options to take if component specific fatigue limits are approached.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
2	Neutron Fluence Monitoring (17.2.1.2)	X.M2	Continue the existing PTN Neutron Fluence Monitoring AMP, including enhancement to: a) Follow the related industry efforts, such as by the PWROG, and use the information from supplemental nozzle region dosimetry measurements and reference cases or other information to provide additional justification for use of the approved WCAP-14040-A or similar methodology for determination of RPV fluence in regions above or below the active fuel region. b) This justification will: • draw from sections 1 and 2 of UFSAR Appendix 4A and • include discussion of the neutron source, synthesis of the flux field and the order of angular quadrature (e.g., S8), etc. used in the estimates for projection of TLAAs to 80 years.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
3	Concrete Containment Unbonded Tendon Prestress (17.2.1.3)	X.S1	Continue the existing PTN Concrete Containment Unbonded Tendon Prestress AMP, including enhancement to: a) Issue ten year interval updates and update the trend lines after each scheduled examination by calculating predicted tendon forces in accordance with NRC RG 1.35.1.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
4	Environmental Qualification of Electric Equipment (17.2.1.4)	X.E1	Continue the existing PTN Environmental Qualification of Electric Equipment AMP, including enhancement to: a) Visually inspect accessible, passive EQ equipment prior to the SPEO and for adverse localized environments that could impact qualified life, and; b) Re-inspect for same as above every 10 years thereafter.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (17.2.2.1)	XI.M1	Continue the existing PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP, including enhancement to: a) Develop a wear depth measurement process for the CRDM head penetrations. b) Incorporate inspections using the demonstrated process at accessible locations to measure depth of wear on the CRDM housing penetration wall associated with contact. c) Develop a procedure to estimate the wall thickness of the accessible CRDM housing penetration wear in the area of interest at the end of the next reactor vessel head inspection interval and compare that projected wall thickness to the thickness used in the design basis analyses to demonstrate validity of the analyses. d) Evaluate industry experience related to CRDM housing penetration wear due to thermal sleeve centering pads and initiatives to measure CRDM housing penetration wear and resulting nozzle wall thickness.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
6	Water Chemistry (17.2.2.2)	XI.M2	Continue the existing PTN Water Chemistry AMP.	Ongoing

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
7	Reactor Head Closure Stud Bolting (17.2.2.3)	XI.M3	Continue the existing PTN Reactor Head Closure Stud Bolting AMP, including enhancement to: a) Include the material inspection and maximum yield strength recommendations, to address reactor head closure stud bolting degradation, provided in RG 1.65 for completeness, b) Revise procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi and revise procedures to note that lubricants cannot contain Molybdenum Disulfide to inhibit corrosion.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
8	Boric Acid Corrosion (17.2.2.4)	XI.M10	Continue the existing PTN Boric Acid Corrosion AMP, including enhancement to: a) Include other potential means to help in the identification of borated water leakage, such as: • Humidity monitors (for trending increases in humidity levels due to unidentified RCS leakage) • Temperature monitors (for trending increases in room/area temperatures due to unidentified RCS leakage) • Containment air cooler thermal performance (for corroborating increases in containment atmosphere temperature or humidity with decreases in cooler efficiency due to boric acid plate out) These results will be reviewed on a yearly basis.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
9	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (17.2.2.5)	XI.M11B	Continue the existing PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, including enhancement to: a) Update the plant modification process to ensure that no additional nickel alloys will be used in reactor coolant pressure boundary applications during the SPEO or that, if used, appropriate baseline and subsequent inspections per MRP inspection guidance will be put in place.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
10	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (17.2.2.6)	XI.M12	Implement the new PTN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
11	Reactor Vessel Internals (17.2.2.7)	XI.M16A	Continue the existing PTN Reactor Vessel Internals AMP, including enhancements to: a) Expand scope to incorporate the change in inspection category for the fuel alignment pins identified by the gap analysis. b) Add to the implementing procedure an explicit statement that there is a 45-day period to notify the NRC of any deviation from the I&E methodology.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
12	Flow-Accelerated Corrosion (17.2.2.8)	XI.M17	Continue the existing PTN Flow-Accelerated Corrosion AMP, including enhancement to: a) Include erosion mechanisms such as cavitation, flashing, droplet impingement, or solid particle impingement for the components that contain treated water (including borated water) or steam. b) Address erosion as an aging mechanism for components that contain treated water (including borated water) or steam. The following should be included: • Guidelines for measuring wall thickness due to erosion. Wall thickness should be trended to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements. • Evaluations of inspection results to determine if assumptions in the extent-of-condition review remain valid. If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities should consider the number or duration of these occurrences. • Performance of periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Ensure that identification of susceptible locations of erosion is based on the extent of condition reviews from corrective actions in response to plant specific and industry OE. Components may be treated in a manner similar to “susceptible-not-modeled” lines discussed in NSAC-202L-R3. Additionally, include guidance from EPRI 1011231 for identifying potential damage locations and EPRI TR-112657 and/or NUREG/CR–6031 guidance for cavitation erosion. d) Perform a re-assessment of piping systems excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L-R3) to ensure the exclusion remains valid and applicable for operation beyond 60 years. If actual wall thickness information is not available for use in this re-assessment, a representative sampling approach will be used. This re-assessment may result in additional inspections. e) Include long-term corrective actions for erosion mechanisms. The effectiveness of the corrective actions should be verified. Include periodic monitoring activities for any component replaced with an alternative material since no material is completely resistant to erosion.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
13	Bolting Integrity (17.2.2.9)	XI.M18	Continue the existing PTN Bolting Integrity AMP, including enhancement to: a) Inspect submerged pressure-retaining bolting when submerged portions of components (e.g., pump casings) are overhauled or replaced during maintenance activities; b) Evaluate closure bolting for piping systems that contain air or gas, for which leakage is difficult to detect, on a case-by-case basis through – • Visual inspection during maintenance activities; • Visual inspection for discoloration of nearby external surfaces; • Monitoring and Trending of pressure decay within an isolated boundary; • Soap bubble testing; or • Thermography when fluid temperature is higher than ambient. c) Ensure any replacement or new pressure-retaining bolting has an actual yield strength less than 150 ksi; d) Ensure that lubricants containing molybdenum disulfide will not be used in conjunction with pressure-retaining bolting; e) Include appropriate acceptance criteria for submerged pressure-retaining bolting and closure bolting for piping systems that contain gas or air for which leakage is difficult to detect.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
14	Steam Generators (17.2.2.10)	XI.M19	Continue the existing PTN Steam Generators AMP, including enhancement to: a) Incorporate the latest EPRI steam generator guidelines per NEI 97-06; b) If the divider plate assemblies are not bounded by industry analyses EPRI 3002002850, schedule a one-time inspection to confirm the effectiveness of the Water Chemistry and Steam Generators AMPs. c) Perform one-time inspection using qualified techniques capable of detecting primary water stress corrosion cracking in the divider plate assemblies and associated welds.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
15	Open-Cycle Cooling Water System (17.2.2.11)	XI.M20	Continue the existing PTN Open-Cycle Cooling Water System AMP, including enhancement to: a) Delineate within the pertinent testing specification the descriptions of the specific aging mechanisms associated with coatings/linings (blistering, cracking, flaking, peeling, delamination, and rusting); b) Ensure that the inspection frequency for ICW piping internal inspections delineated in the pertinent testing specification should not exceed 5 years. In addition, changes to piping internal inspection intervals are to be established by a coating specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54. For cementitious ICW piping coatings within the scope of the program, inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience. c) Ensure the pertinent testing specification coating acceptance criteria include the following: • There are no indications of peeling or delamination.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size or frequency should not be increasing between inspections (e.g., ASTM D714-02, “Standard Test Method for Evaluating Degree of Blistering of Paints”). • Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. • Minor cracking and spalling of cementitious coatings/ linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material. • As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. • Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in site-specific design requirements specific to the coating/lining and substrate.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
16	Closed Treated Water Systems (17.2.2.12)	XI.M21A	Continue the existing PTN Closed Treated Water Systems AMP, including enhancement to: a) Expand the scope of the component inspections/testing to include any closed cooling/treated water system components that are identified in the AMR reports, which are not presently listed in the component inspection procedure. b) Perform visual inspections of all in-scope heat exchanger surfaces for cleanliness in order to assure heat transfer capability. Alternatively, functional testing can be performed instead. c) Include the following NUREG-2191 inspection requirements: At a minimum, in each 10-year period during the SPEO, a representative sample of components is inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The sample population is defined as follows: • 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. d) Evaluate water chemistry testing results and component inspection/testing results against acceptance criteria to confirm that the sampling bases will maintain components’ intended functions throughout SPEO based on projected rate and extent of degradation.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			e) Align the program with the latest industry document, EPRI TR-3002000590, Closed Cooling Water Chemistry Guideline. f) Ensure that the following additional inspections and actions are required if a post-repair/replacement inspection or subsequent inspection fails to meet acceptance criteria: • The number of increased inspections is determined in accordance with PTN's corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria. • If subsequent inspections do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis is conducted to determine the further extent of inspections. • Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since Turkey Point is a multi-unit site, the additional inspections include inspections at all of the units with the same material, environment, and aging effect combination. • The additional inspections are completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted. g) Ensure that visual inspections of the closed treated water systems components internal surfaces are conducted whenever their respective system boundary is opened.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
17	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (17.2.2.13)	XI.M23	Continue the existing PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, including enhancement to: a) Perform visual inspections on the in-scope bolted connections and structural components for conditions indicative of loss of preload (loss of material due to corrosion, cracking, and loose bolts, missing or loose nuts), and evaluate and repair if necessary, in accordance with ASME B30.2, B30.11, or other applicable industry standard in the ASME B30 series. In addition to previously in-scope components, this includes the fuel transfer machines, spent fuel bridge cranes, and the following monorails and rigging beams: • Charging pump monorails • Safety injection pump monorails • Main steam platform monorails • Fuel pool bulkhead monorails • ICW valve pit rigging beam • TPCW basket strainer monorail b) Align procedures with ASME B30.2, 2005 edition, and inspect for deformed, cracked, and corroded members, and for loose or missing fasteners, such as, but not limited to bolts, nuts, pins or rivets, as described in ASME B30.2, Section 2-2.1.3. Aligning with ASME B30.2 2005 edition also ensures that the correct acceptance criteria and corrective actions are used, and to ensure that visual inspections are performed at the required frequency. According to ASME B30.2, inspections are performed within the following intervals:	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• “Periodic” visual inspections by a designated person are required and documented yearly for normal service applications (ASME B30.2, Section 2-2.1.1). • A crane that is used in infrequent service, which has been idle for a period of 1 year or more, shall be inspected before being placed in service in accordance with the requirements listed in ASME B30.2 paragraph 2-2.1.3 (periodic inspection).	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
18	Compressed Air Monitoring (17.2.2.14)	XI.M24	Continue the existing PTN Compressed Air Monitoring AMP, including enhancement to: a) Include acceptance criteria for compressed air moisture content and contaminant limits based on manufacturer recommendations, pertinent industry guidance (ASME OM-2012, ANSI/ISA-S7.0.0.01-1996, and EPRI TR-108147), and site OE. b) Perform opportunistic visual inspections of accessible internal surfaces for evidence of corrosion or corrosion products at frequencies based on industry guidance and site OE. c) Include description of qualifications for personnel performing a) the inspections for evidence of corrosion or corrosion products and b) air quality tests/checks. d) Include trending for air quality, moisture content, and signs of corrosion with checking for unusual trends and comparison to previous tests. e) Address interface with PTN procurement and receiving functions regarding the quality of bottled gas (e.g., cover and backup nitrogen bottles) supplied to PTN. f) Perform assessment of existing GL 88-14 activities	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
19	Fire Protection (17.2.2.15)	XI.M26	Continue the existing PTN Fire Protection AMP, including enhancement to: a) Inspect for corrosion and cracking on all in-scope fire dampers assemblies with an acceptance criteria of no visual indications of cracks or corrosion that could affect the components' intended function; b) Ensure that personnel that inspect penetration seals, walls, ceilings, floors, doors, fire damper assemblies, and other fire barrier materials are qualified per the NRC-approved fire protection program (NFPA 805) to perform such inspections; c) Document any degradation identified in the halon fire suppression system tests and include in the trending analysis; d) Project identified degradation until the next scheduled inspection when practical; e) Evaluate trending inspection results against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) and the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, then inspection frequencies are adjusted as determined by the PTN corrective action program.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
20	Fire Water System (17.2.2.16)	XI.M27	Continue the existing PTN Fire Water System AMP, including enhancement to: a) Replace sprinklers before they reach 50 years of service or test a representative sample of sprinklers from one or more sample areas using the guidance of NFPA 25; b) Perform volumetric wall thickness inspections on the portions of the water-based FPS components periodically subjected to flow but normally dry; c) Perform additional volumetric wall thickness inspections after surface irregularities, indicative of corrosion or erosion, are visually detected; d) Perform testing and visual inspections in accordance with the methods and intervals from Table XI.M27-1 from NUREG-2191, (based on NFPA 25, 2011 Ed.) and perform external visual inspections on a refueling outage interval. These inspections and tests include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes. e) Perform volumetric inspections from the inside surface of the raw water tanks (T63A/B) in accordance with NUREG-2191, Table XI.M29-1. These inspections are required to be performed for each 10-year period starting 10 years prior to the SPEO.	This AMP is implemented and its inspections and tests begin 5 years prior to the SPEO. Inspections or test that are required to be completed prior to SPEO are completed no later than 6 months prior to SPEO or no later than the last RFO prior to SPEO. The corresponding dates are as follows: PTN3: 7/19/2027 - 1/19/2032 PTN4: 4/20/2028 - 10/10/2032 Perform the initial tank bottoms inspections no earlier than 10 years prior to the SPEO. The inspections are required to be completed no later than 6 months prior to SPEO. The corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			f) Perform the following augmented testing and inspections beyond those of NUREG-2191 Table XI.M27-1 on the portions of water-based FPS components that have been wetted but are normally dry and either cannot be drained or allow water to collect, such as dry-pipe or preaction sprinkler system piping and valves: • In each 5-year interval, beginning 5 years prior to the SPEO, either conduct a flow test/flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of the piping segments that either cannot be drained or allow water to collect. • In each 5-year interval of the SPEO, 20 percent of the length of piping segments that either cannot be drained or allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, erosion, MIC). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping. If the results of a 100 percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			g) Extrapolate the results of the inspections of the above grade FPS piping to evaluate the condition of buried and underground fire protection piping for the purpose of identifying inside diameter loss of material if the environment (e.g., type of water, flowrate, temperature) and material that exist on the interior surface of the underground piping are similar to the conditions that exist within the above grade FPS piping; h) Project identified degradation until the next scheduled inspection and evaluate results against acceptance criteria (e.g., maintaining minimum design wall thicknesses) to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO. If the condition of the piping/component will not meet acceptance criteria, then a condition report is written and the component is evaluated for repair/replacement. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			i) Perform additional tests if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation, then are conducted. The number of increased tests is determined in accordance with the PTN corrective action program; however, there are no fewer than two additional tests for each failed test. The additional inspections are completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent-of-condition/cause analysis is conducted to determine the further extent of test, which include inspections at all of the units with the same material, environment, and aging effect combination.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
21	Outdoor and Large Atmospheric Metallic Storage Tanks (17.2.2.17)	XI.M29	Continue the existing PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, including enhancement to: a) Add the U3 EDG FOST and associated acceptance criteria to the scope of the AMP; b) Convert one-time inspections for original license renewal to the following periodic inspections, with the associated frequencies and acceptance criteria – • Visual examination of tank internal surfaces • Tank bottom thickness measurements Note: These additional inspections will be conducted each 10-year interval starting 10 years prior to entering the SPEO. c) Clarify that increased inspections address each tank in a material environment combination in the same inspection interval, including tanks from both units, IF only one tank is inspected and does not meet acceptance criteria, which requires corrective action.	This AMP is implemented and inspections or tests begin no earlier than 10 years prior to the SPEO. Inspections or tests that are required to be completed prior to the SPEO are completed no later than 6 months prior to SPEO or no later than the last RFO prior to SPEO. The corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
22	Fuel Oil Chemistry (17.2.2.18)	XI.M30	Continue the existing PTN Fuel Oil Chemistry AMP, including enhancement to: a) Perform periodic draining, cleaning, and visual inspection (and volumetric inspection if degradation is identified) of the in-scope components. This will occur during the 10-year period prior to the SPEO and at least once every 10-years during the SPEO; b) Monitor the moisture, sediment content, total particulate concentration, and microbiological contamination levels of the in-scope components, compare to acceptance criteria consistent with industry standards, and trend the results; c) Perform sampling consistent with applicable industry standards, such as ASTM 4057, to address multilevel and/or bottom samples; d) Perform volumetric inspections on any degradation identified during visual inspection. Include thickness measurements of the bottoms of the in-scope tanks or, in the case of the Unit 4 EDG DOSTs, thickness measurements of the carbon steel tank liners, and evaluated against the applicable design thickness and corrosion allowance, and trend the results; e) Drain and clean the Unit 3 EDG skid tanks and SSGF pump skid tank to the greatest extent practical and perform a visual inspection of accessible locations; f) Perform a one-time inspection of selected components exposed to diesel fuel oil, prior to the SPEO and in accordance with the PTN One-Time Inspection AMP, to verify the effectiveness of this AMP;	This AMP is implemented and inspections begin no earlier than 10 years prior to the SPEO. Inspections that are required to be completed prior to the SPEO are completed no later than six months prior to SPEO or no later than the last RFO prior to SPEO. The corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			g) Provide corrective actions, such as addition of a biocide, to be taken should testing detect the presence of microbiological activity in stored diesel fuel, and removal of water found during sampling.	
23	Reactor Vessel Material Surveillance (17.2.2.19)	XI.M31	Continue the existing PTN Reactor Vessel Material Surveillance AMP.	Ongoing
24	One-Time Inspection (17.2.2.20)	XI.M32	Implement the new PTN One-Time Inspection AMP.	Implement AMP and start inspections 10 years prior to the SPEO. Complete pre-SPEO inspections no later than 6 months or the last RFO prior to SPEO. Corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
25	Selective Leaching (17.2.2.21)	XI.M33	Implement the new PTN Selective Leaching AMP.	Implement AMP and start inspections no earlier than 10 years prior to the SPEO. Complete the one-time inspection and the first periodic inspection no later than 6 months or the last RFO prior to SPEO. Corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032
26	ASME Code Class 1 Small-Bore Piping (17.2.2.22)	XI.M35	Continue the existing PTN ASME Code Class 1 Small-Bore Piping AMP, including enhancement to: a) Perform the new one-time inspection of small-bore piping using the methods, frequencies, and accepted criteria; b) Evaluate the results to determine if additional or periodic inspections are required and perform any required additional inspections;	Implement AMP and complete inspections within 6 years prior the SPEO. Complete pre-SPEO inspections no later than 6 months or the last RFO prior to SPEO. Corresponding dates are as follows: PTN3: 7/19/2026 - 1/19/2032 PTN4: 4/10/2027 - 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
27	External Surfaces Monitoring of Mechanical Components (17.2.2.23)	XI.M36	Continue the existing PTN External Surfaces Monitoring of Mechanical Components AMP, including enhancement to: a) Elastomeric and flexible polymeric components are monitored through a combination of visual inspection and manual or physical manipulation of the material. Visual inspections cover 100 percent of accessible component surfaces. Manual or physical manipulation of the material includes touching, pressing on, flexing, bending, or otherwise manually interacting with the material in order to reveal changes in material properties, such as hardness, and to make the visual examination process more effective in identifying aging effects such as cracking. The sample size for manipulation is at least 10 percent of available surface area. The inspection parameters for elastomers and polymers shall include the following: • Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”) • Loss of thickness • Discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation) • Exposure of internal reinforcement for reinforced elastomers • Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Ensure that accumulation of debris on in-scope components is monitored. c) Ensure that seals, insulation jacketing, and air-side heat exchangers are inspected components. d) Inspections are to be performed by personnel qualified in accordance with site procedures and programs to perform the specified task, and when required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), inspections are conducted in accordance with the applicable code requirements. e) Perform inspections for loss of material, cracking, changes in material properties, hardening or loss of strength (of elastomeric components), reduced thermal insulation resistance, loss of preload for ducting closure bolting, and reduction of heat transfer due to fouling at an inspection frequency of every refueling outage for all in-scope non-stainless steel and non-aluminum components, which include metallic, polymeric, insulation jacketing (insulation when not jacketed), and cementitious components. Non-ASME Code inspections and tests should include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings. Surfaces that are not readily visible during plant operations and refueling outages should be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			f) Surface examinations, or VT-1 examinations, are conducted on 20 percent of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. The provisions of GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to conduct inspections in a more severe environment and combination of air environments may be incorporated for these inspections. g) Alternative methods for detecting moisture inside piping insulation (thermography, neutron backscatter devices, and moisture meters) are to be used for inspecting piping jacketing that is not installed in accordance with site-specific procedures (i.e., no minimum overlap, wrong location of seams, etc.). h) Include the following information: • Component surfaces that are insulated and exposed to condensation (because the in-scope component is operated below the dew point), and insulated outdoor components, are periodically inspected every 5 years during the SPEO.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• For all outdoor components and any indoor components exposed to condensation (because the in-scope component is operated below the dew point), inspections are conducted of each material type (e.g., steel, SS, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. Inspections for cracking due to SCC in aluminum components need not be conducted if it has been determined that SCC is not an applicable aging effect.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			i) Include guidance from EPRI TR-1007933 “Aging Assessment Field Guide” and TR-1009743 “Aging Identification and Assessment Checklist” on the evaluation of materials and criteria for their acceptance when performing visual/tactile inspections. j) Include information on the additional inspections that are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. To ensure that the sampling-based inspections detect cracking in aluminum and stainless steel components, additional inspections should be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site’s corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria. The additional inspections are completed within the interval (i.e., 5-year inspection interval) in which the original inspection was conducted. If subsequent inspections do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis are conducted to determine the further extent of inspections. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since PTN is a multi-unit site, the additional inspections include inspections at all of the units with the same material, environment, and aging effect combination.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			Revise the Corrective Action Program procedure to point to appropriate External Surfaces Monitoring of Mechanical Components AMP procedure for corrective actions.	
28	Flux Thimble Tube Inspection (17.2.2.24)	XI.M37	Continue the existing PTN Flux Thimble Tube Inspection AMP, including enhancement to: a) Establish the interval between inspections such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. b) Remove from service the flux thimble tubes that cannot be inspected over the tube length, yet are subject to wear due to restriction or other defects, but cannot be shown by analysis to be satisfactory for continued service. This ensures the integrity of the RCS pressure boundary.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
29	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (17.2.2.25)	XI.M38	Implement the new PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
30	Lubricating Oil Analysis (17.2.2.26)	XI.M39	Continue the existing PTN Lubricating Oil Analysis AMP, including enhancement to: a) Monitor for and manage the aging effects associated with in-scope components that are exposed to an environment of lubricating oil. The PTN Lubricating Oil Analysis AMP's in-scope components include piping, piping components, heat exchanger tubes, and reactor coolant pump elements exposed to lubricating oil. The PTN Lubricating Oil Analysis AMP also manages any other plant components subject to lubricating oil environments and listed in applicable Aging Management Reviews (AMR). b) Maintain contaminants in the in-scope lubricating oil systems within acceptable limits through periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with industry standards. All lubricating oil analysis results are to be reviewed and trended to determine if alert levels or limits have been reached or exceeded, as well as, if there are any unusual or adverse trends associated with the oil sample. c) Sampling and testing of old (used) oil is to be performed following periodic oil changes or on a schedule consistent with equipment manufacturer's recommendations or industry standards (e.g., ASTM D6224-02). Plant specific operating experience (OE) may also be used to adjust the recommended schedule for periodic sampling and testing, when justified by prior sampling results.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			d) Compare the particulate count of the samples with acceptance criteria for particulates. The acceptance criteria for water and particle concentration within the oil must not exceed limits based on equipment manufacturer's recommendations or industry standards. If an acceptance criteria limit is reached or exceeded, actions to address the condition are to be taken. Corrective actions may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the specified lubricating oil system. e) Phase-separated water in any amount is not acceptable. If phase-separated water is identified in the sample, then corrective actions are to be initiated to identify the source and correct the issue (e.g., repair/replace component or modify operating conditions).	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
31	Monitoring of Neutron-Absorbing Materials other than Boraflex (17.2.2.27)	XI.M40	Continue the existing (previously only credited for Metamic® inserts) PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP, including enhancement to: a) Inspect and test Metamic® inserts on a frequency dependent on the condition of the neutron-absorbing material and determined and justified with PTN-specific OE. For each Metamic® insert, the maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE; b) Compare observations and measurements from the periodic inspections and coupon testing to baseline information or prior measurements and analyses for trending analysis, projecting future degradation, and projecting the future subcriticality margin of the SFP. This trending will also consider differences in exposure conditions, venting, spent fuel rack differences, etc. for each Metamic® insert or coupon. c) Initiate corrective actions (e.g., add neutron-absorbing capacity with an alternate material, or apply other available options) to maintain the subcriticality margin if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected degradation of the neutron-absorbing material.	Complete the initial Boral® testing and inspections no later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			d) Manage aging effects associated with the Boral® panels in the SFP cask area by monitoring for loss of material and changes in dimension that could result in loss of neutron-absorbing capability of the Boral® panels. Monitor parameters associated with the physical condition of the Boral® panels and include in-situ gap formation, geometric changes as observed from coupons or in situ, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the Boral® panels. These parameters are monitored using coupon and/or direct in-situ testing of the Boral® panels to identify their associated loss of material and degradation of neutron absorbing capacity. The frequency of the inspection and testing depends on the condition of the neutron-absorbing material and is determined with site-specific OE; however, the maximum interval between these inspections is not to exceed 10 years, regardless of OE. Compare the Boral® inspection and testing measurements to baseline values for trending analysis and projecting future panel degradation and SFP subcriticality margins. The degradation trending must be based on samples that adequately represent the entire Boral® panel population, and the trending must consider differences in sample exposure conditions, differences in spent fuel cask racks, and	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			possibly other considerations. The new Boral® panel surveillance acceptance criteria for the obtained inspection, testing, and analysis measurements must ensure that the 5 percent subcriticality margin for the SFP will be maintained, otherwise corrective actions need to be implemented.	
32	Buried and Underground Piping and Tanks (17.2.2.28)	XI.M41	Implement the new PTN Buried and Underground Piping and Tanks AMP. Install cathodic protection systems, and perform effectiveness reviews in accordance with Table XI.M41-2 in NUREG-2191, Section XI.M41.	Implement AMP and start inspections no earlier than 10 years prior to the SPEO. Complete pre-SPEO inspections no later than 6 months or the last RFO prior to SPEO. Corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032
33	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (17.2.2.29)	XI.M42	Implement the new PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP.	Implement AMP and start inspections no earlier than 10 years prior to the SPEO. Complete pre-SPEO inspections no later than 6 months or the last RFO prior to SPEO. Corresponding dates are as follows: PTN3: 7/19/2022 - 1/19/2032 PTN4: 4/10/2023 - 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
34	ASME Section XI, Subsection IWE (17.2.2.30)	XI.S1	Continue the existing PTN ASME Section XI, Subsection IWE AMP, including enhancement to: a) Include preventive actions, consistent with industry guidance, to provide reasonable assurance that bolting integrity is maintained for structural bolting, and if high strength bolting is used, the appropriate guidance in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using High-Strength Bolts” is to be considered. b) Implement a one-time inspection of metal liner surfaces that samples randomly selected as well as focused locations susceptible to loss of thickness due to corrosion from the concrete side if triggered by site-specific OE identified through code inspections.	Complete any applicable pre-SPEO one-time inspections no later than 6 months or the last RFO prior to SPEO. Corresponding dates are as follows: PTN3: 1/19/2032 PTN4: 10/10/2032
35	ASME Section XI, Subsection IWL (17.2.2.31)	XI.S2	Continue the existing PTN ASME Section XI, Subsection IWL AMP, including enhancement to: a) Calculate the predicted tendon forces in accordance with NRC RG 1.35.1, which provides an acceptable methodology for use through the SPEO.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
36	ASME Section XI, Subsection IWF (17.2.2.32)	XI.S3	Continue the existing PTN ASME Section XI, Subsection IWF AMP, including enhancement to: a) Store high strength bolts in accordance with Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using High-Strength Bolts”. b) Perform a one-time inspection, within 5 years prior to entering the SPEO, of an additional 5 percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports, which are not exempt from examination, that is focused on supports selected from the remaining IWF population that are considered most susceptible to age-related degradation. c) Include physical (tactile) examination of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect due to aging. d) Perform volumetric examination, comparable to Table IWB-2500-1, Examination Category B-G-1, at least once per interval for a sample of high-strength bolting selected to provide reasonable assurance that SCC is not occurring for the entire population of high-strength bolts. Alternatively, a site-specific justification for waiving the volumetric examination may be documented.	At 5 years prior to the SPEO, start one-time inspections. Complete pre-SPEO inspection no later than 6 months or the last refueling outage prior to SPEO. Corresponding dates are as follows: PTN3: 7/19/2027 - 1/19/2032 PTN4: 4/10/2028 - 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
37	10 CFR Part 50, Appendix J (17.2.2.33)	XI.S4	Continue the existing PTN 10 CFR Part 50, Appendix J AMP, including enhancement to: a) Augment the existing program required by 10 CFR Part 50 Appendix J, by ensuring that all containment pressure-retaining components are managed for age-related degradation. b) Update the definitions for Type A, Type B, and Type C tests in the fleet and governing procedures to closer align with their respective definitions in 10 CFR Part 50, Appendix J, Section II.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
38	Masonry Walls (17.2.2.34)	XI.S5	Continue the existing PTN Masonry Walls AMP, including an enhancement to: a) Add the inspection of intake and yard structure masonry walls that are credited for flood protection.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
39	Structures Monitoring (17.2.2.35)	XI.S6	Continue the existing PTN Structures Monitoring AMP, including enhancement to: a) Add the following components and commodity groups to the list of inspected items: • Fan/filter intake hood (Auxiliary Building) • Pipe trench penetration and fire seals used for flood protection • Stop logs • Doors (Diesel Driven Fire Pump Enclosure) • Louvers (Diesel Driven Fire Pump Enclosure) • HVAC roof hoods (Emergency Diesel Generator Building) • Louvers (Emergency Diesel Generator Building) • U4 Diesel Oil Storage Tank liner • Electrical Enclosures (Intake Structure) • Structural Truck Bridge (Intake Structure) • New Fuel Storage Components • NaTB sump fluid pH control basket • Drains, drain plugs (stored in various locations) that are credited for external flood protection • Berm and paved ramp that are credited for external flood protection b) Revise storage requirements for high strength bolts in accordance with Section 2 of RSCS publication “Specification for Structural Joints Using High-Strength Bolts”; c) Revise inspection procedure to include monitoring for loss of material, missing or loose nuts/bolts, and other conditions that indicate loss of preload for structural bolting with acceptance criteria that these are not acceptable without engineering evaluation.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			d) Clarify that inspections of elastomers will include tactile manipulation and the acceptance criteria for inspections of structural sealants will ensure loss of material, cracking, and hardening will not result in loss of sealing. e) Revise inspections procedures to reference SEI/ASCE 11 and the American Institute of Steel Construction Manual f) Perform evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. The respective evaluation/ inspection/ testing interval is not to exceed 5 years. g) Revise inspection procedures to include guidance on monitoring for indications of cracking and expansion due to reaction with aggregates in concrete structures.	

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
40	Inspection of Water-Control Structures Associated with Nuclear Power Plants (17.2.2.36)	XI.S7	Continue the existing PTN Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, including enhancement to: a) Store high strength bolts in accordance with Section 2 of Research Council for Structural Connections publication "Specification for Structural Joints Using High-Strength Bolts"; b) Monitor structural bolting for loss of material, loose bolts, missing or loose nuts, and other conditions that indicate loss of preload. Loose bolts and nuts are not acceptable unless accepted by engineering evaluation; c) Monitor for increases in porosity, permeability, and conditions at junctions with abutments and embankments; d) Perform focused inspections of below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years. Submerged concrete structures may be inspected during periods of low tide or when dewatered or using divers. Areas covered by silt, vegetation, or marine growth are not considered inaccessible and are cleaned and inspected in accordance with the standard inspection frequency; e) Include monitoring for siltation or undesirable vegetation, with respect to cooling canal inspections, so that the cooling canal function does not become impaired; f) Include the Reinforced Concrete Shield Wall for the Discharge Structure in the list of components inspected in the pertinent implementing procedure.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
41	Protective Coating Monitoring and Maintenance (17.2.2.37)	XI.S8	Continue the existing PTN Protective Coating Monitoring and Maintenance AMP, including enhancement to: a) Perform aging management surveillance in accordance with the guidance of Regulatory Position C4 of RG 1.54 Revision 2 and ASTM D 5163-08 (rather than ASTM D 5163-96). Use inspection and documentation parameters listed in ASTM D 5163-08 subparagraph 10.2.1 through 10.2.6, 10.3, and 10.4. Use observation and testing methods listed in ASTM D 5163-08 subparagraphs 10.2.3 and 10.2.4; b) Perform inspections using individuals trained in the applicable reference standards of ASTM D5498. c) Implement any changes into the PTN Protective Coatings Monitoring and Maintenance AMP that may result from the resolution of the Generic Safety Issue (GSI) 191 ECCS strainer blockage issue, or if there is no impact, then inform the NRC.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
42	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (17.2.2.38)	XI.E1	Continue the existing PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP, including enhancement to: a) Expand program scope to include areas outside of Containment that contain in-scope cables and connections. b) Identify adverse localized environments utilizing the guidance in NUREG-2191, Section XI.E1 and EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments." Palo Alto, California: Electric Power Research Institute, June 1999. c) Inspect for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, or moisture). d) Review site-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation during the original PEO. Evaluate to confirm that the dispositioned corrective actions continue to support in-scope cable and connection intended functions during the SPEO. e) Ensure personnel involved with field implementation are qualified on cable aging inspection techniques. f) Utilize sampling methodology consistent with guidance of Section XI.E1 of NUREG-2191, if cable testing is deemed necessary.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032 Required pre-SPEO inspections that require plant outage are completed no later than the last RFO prior to the SPEO.

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
43	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits (17.2.2.39)	XI.E2	Implement the new PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
44	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (17.2.2.40)	XI.E3A	Implement the new PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
45	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (17.2.2.41)	XI.E3B	Implement the new PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
46	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (17.2.2.42)	XI.E3C	Implement the new PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
47	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (17.2.2.43)	XI.E6	Implement the new PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
48	High-Voltage Insulators (17.2.2.44)	XI.E7	Implement the new PTN High-Voltage Insulators AMP.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032 Required pre-SPEO inspections that require plant outage are completed no later then the last RFO prior to the SPEO.
49	Pressurizer Surge Line Fatigue (17.2.3.1)	N/A – PTN site-Specific Program	Continue existing PTN Pressurizer Surge Line Fatigue AMP.	Ongoing
50	Quality Assurance Program (17.1.3)	Appendix A	Continue the existing FPL QA Program at PTN.	Ongoing

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
51	Operating Experience Program (17.1.4)	Appendix B	Continue the existing PTN OE Program, including enhancement to: a) Update program procedures to specify SLR-ISGs and GALL-SLR revisions as required OE review items; b) Update program procedures to develop an OE trend code and specify a requirement to perform OE trending. c) Create a procedure for evaluating OE for the aging management related criteria included in the following items: • Systems, structures, and components; • Materials, • Environments, • Aging effects, • Aging mechanisms, • AMPs, and; • The activities, criteria, and evaluations integral to the elements of the AMPs. d) Update AMP owner training procedure to perform training on a periodic basis.	No later than the date that the subsequent operating license is renewed.
52	Non-Containment Structure Aging Management Review	N/A	Continue monitoring of spent fuel pool water level and leakage from leak chase channels.	Ongoing

Table 17-3
List of SLR Commitments and Implementation Schedule (Continued)

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
53	Containment Structure and Internal Structural Components Aging Management Review	N/A	Follow the ongoing industry efforts that are clarifying the effects of irradiation on concrete and corresponding aging management recommendations, including: a) Ensure their applicability to the PTN Unit 3 and Unit 4 primary shield wall and associated reactor vessel supports; b) Update design calculations, as appropriate, and; c) Develop an informed site-specific program, if needed.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032
54	Nonsafety-related SSCs that are not Directly Connected to Safety-Related SSCs but have the Potential to Affect Safety-Related SSCs Through Spatial Interactions Screening Document	N/A	Minimize the potential for indoor abandoned equipment outside containment to leak or spray on safety-related equipment by performing the following: a) Update plant procedures to require the periodic venting and draining of indoor abandoned equipment located outside containment that is directly connected to in-service systems; b) Verify that abandoned equipment that is no longer directly connected to in-service systems is vented and drained.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

17.5 REFERENCES

Federal Regulations

1. *U.S. Code of Federal Regulations*, Title 10, Part 50 (10 CFR 50), “Domestic Licensing of Production and Utilization Facilities”

   a. 10 CFR 50.2, “Definitions”

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

   c. 10 CFR 50.55a, “Codes and Standards”

   d. 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events”

   e. 10 CFR 50.61a, “Alternate Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events”

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

   g. 10 CFR 50.90, “Amendment of License or Construction Permit at Request of Holder”

   h. 10 CFR Part 50, Appendix A, “General Design Criteria for Nuclear Power Plants”

   i. 10 CFR Part 50, Appendix G, “Fracture Toughness Requirements”

   j. 10 CFR Part 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements”

   k. 10 CFR Part 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors”

2. *U.S. Code of Federal Regulations*, Title 10, Part 54, (10 CFR 54), “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”.

   a. 10 CFR 54.21, “Contents of Application--Technical Information”

NRC (Generic Letters, NUREGs, Regulatory Guides, Information Notices)

3. NRC, DOR Guidelines, “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors,” U. S. Nuclear Regulatory Commission, Washington D.C., June 1979.

4. NRC, Generic Safety Issue 190, “Fatigue Evaluation of Metal Components for 60-Year Plant Life,” U. S. Nuclear Regulatory Commission, Washington D.C.

5. NRC, NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment,” Agencywide Documents Access and Management System (ADAMS) Accession No. ML031480402, U. S. Nuclear Regulatory Commission, Washington D.C., July 1981.

6. NRC, NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” ADAMS Accession No. ML070250180, U.S. Nuclear Regulatory Commission, Washington D.C., July, 1980.

7. NRC, NUREG-0737, “Clarification of TMI Action Plan Requirements,” ADAMS Accession No. ML051400209 U.S. Nuclear Regulatory Commission, Washington D.C., November 1980.

8. NRC, NUREG-1061, Volume 3, “Report of the NRC Piping Review Committee; Evaluation of Potential for Pipe Breaks,” ADAMS Accession No. ML093170485, U.S. Nuclear Regulatory Commission, Washington D.C., November 1984.

9. NRC, NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” ADAMS Accession No. ML031430208, U.S. Nuclear Regulatory Commission, Washington D.C., June 1990.

10. NRC, NUREG-1759, “Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4,” U.S. Nuclear Regulatory Commission, Washington D.C., April 2002.

11. NRC, NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” U.S. Nuclear Regulatory Commission, Washington D.C., Volumes 1 and 2, July 2017.

12. NRC, NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” U.S. Nuclear Regulatory Commission, Washington D.C., July 2017.

13. NUREG/CR-5999, “Interim Fatigue Design Curves for Carbon, Low-Alloy, and Austenitic Stainless Steels in LWR Environments,” U.S. Nuclear Regulatory Commission, Washington D.C., August 1993.

14. NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,” ADAMS Accession No. ML031480219, U.S. Nuclear Regulatory Commission, Washington D.C., March 1995.

15. NRC, Regulatory Guide 1.26, “Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants,”

ADAMS Accession No. ML070290283, U.S. Nuclear Regulatory Commission, Washington D.C., March 2007.

16. NRC, Regulatory Guide 1.35.1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments,” ADAMS Accession No. ML003740040, U.S. Nuclear Regulatory Commission, Washington D.C., July 1990.

17. NRC, Regulatory Guide 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants,” Revision 2, ADAMS Accession No. ML102230344, U.S. Nuclear Regulatory Commission, Washington D.C., October 2010.

18. NRC, Regulatory Guide 1.65, Revision 1, “Materials and Inspections for Reactor Vessel Closure Studs,” ADAMS Accession No. ML092050716. U.S. Nuclear Regulatory Commission, Washington D.C., April 2010.

19. NRC, Regulatory Guide 1.89, Revision 1, “Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants,” ADAMS Accession No. ML031320126, U. S. Nuclear Regulatory Commission, June 1984.

20. NRC, Regulatory Guide 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” ADAMS Accession No. ML031430205, U.S. Nuclear Regulatory Commission, Washington D.C., May 1988.

21. NRC, Regulatory Guide 1.127, Revision 2, “Criteria and Design Features for Inspection of Water-Control Structures Associated with Nuclear Power Plants,” ADAMS Accession No. ML15107A412, U.S. Nuclear Regulatory Commission, Washington D.C., February 2016.

22. NRC, Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 3, ADAMS Accession No. ML113610098, U.S. Nuclear Regulatory Commission, Washington D.C., May 2012.

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26. NRC, Generic Letter 88-14, “Instrument Air Supply Problems Affecting Safety-Related Components,” ADAMS Accession No. ML113110548, U.S. Nuclear Regulatory Commission, Washington D.C., August 8, 1988.

27. NRC, Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning,” U.S. Nuclear Regulatory Commission, Washington D.C., May 2, 1989.

28. NRC, Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Components,” U.S. Nuclear Regulatory Commission, Washington D.C., July 1989.

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30. NRC, Information Notice (IN) 87-44, “Thimble Tube Thinning in Westinghouse Reactors,” U.S. Nuclear Regulatory Commission, Washington D.C., September 16, 1987.

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Appendix A
Attachment 1
USFAR Changes

Attachment 1 to Appendix A provides a markup of the Turkey Point Units 3 and 4 UFSAR delineating UFSAR changes that will be required for subsequent license renewal.

UFSAR Chapter 4 Changes

Over the range from 15% full power up to but not exceeding 100% of full power, the Reactor Coolant System and its components are designed to accommodate 10% of full power step changes in unit load and 5% of full power per minute ramp changes without reactor trip. The turbine bypass and steam dump system make it possible to accept a step load decrease of 50% of full power without reactor trip.

4.1.6 SERVICE LIFE

The service life of Reactor Coolant System pressure components depends upon the material irradiation, unit operational thermal cycles, quality manufacturing standards, environmental protection, and adherence to established operating procedures.

The reactor vessel is the only component of the Reactor Coolant System which is exposed to a significant level of neutron irradiation and it is therefore the only component which is subject to any appreciable material irradiation effects. The NDTT shift of the vessel material and welds, due to radiation damage effects, is monitored by a radiation damage surveillance program which conforms with ASTM - E 185 standards.

Reactor vessel design is based on the transition temperature method of evaluating the possibility of brittle fracture of the vessel material, as result of operations such as leak testing and heatup and cooldown.

To establish the service life of the Reactor Coolant System components as required by the ASME (part III), Boiler and Pressure Vessel Code for Class "A" Vessels, the unit operating conditions have been established for the initial 40 year design life. These operating conditions include the cyclic application of pressure loadings and thermal transients. The evaluation for extended plant design life concludes that the 40-year design cycles envelope the ~~60~~80-year extended design life.

The number of thermal and loading cycles used for design purposes are listed in Table 4.1-8. Component Cyclic or Transient Limits are listed in Table 4.1-10

Metal fatigue considerations, including Reactor vessel underclad cracking, have also been evaluated for the extended plant life as discussed in UFSAR Chapter 16. The analysis associated with reactor vessel underclad crack growth has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii) as indicated in UFSAR Chapter 16. Underclad cracking has been evaluated by Westinghouse in WCAP-15338, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants.”

TABLE 4.1-8
DESIGN THERMAL AND LOADING CYCLES - ~~6~~80 YEARS

Transient Design Condition	Design Cycles
1. Station heatup at 100°F per hour	200
2. Station cooldown at 100°F per hour	200
3. Station loading at 5% of full power/min	14,500(5)
4. Station unloading at 5% of full power/min	14,500(5)
5. Step load increase of 10% of full power (but not to exceed full power)	2000
6. Step load decrease of 10% of full power	2000
7. Step load decrease of 50% of full power	200
8. Reactor trip 400	
9. Hydrostatic test at 3107 psig pressure, 100°F temperature	1(3)
10. Hydrostatic test at 2485 psig pressure and 400°F temperature	5(4)
11. Steady state fluctuations	00(1)
12. Feedwater Cycling at Hot Standby	2000(2)

Notes:

(1) Not counted, not significant contributor to fatigue usage factor.

(2) Not counted, Intermittent slug feeding at hot standby not performed.

(3) Limited by Seam Generator Analysis. Represents pre-operational hydrostatic test.

(4) Limited by Reactor Coolant Pump Analysis.

(5) The loading and unloading design cycle limit for baffle-former bolt only is being lowered from 14,500 to 2,200 due to EPU RCS conditions.

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Framatome ANP Topical Report BAW-2308, Revisions 1A and 2A (References 10 and 11) provide new initial weld materials properties. The NRC approved the exemption request to use these values in a letter dated March 11, 2010 (Reference 12).

The techniques used to measure and predict the integrated fast neutron (E > 1 Mev) fluxes at the sample locations are described in Appendix 4A. The calculation method used to obtain the maximum neutron (E > 1 Mev) exposure of the reactor vessel is identical to that described for the irradiation samples. Since the neutron spectra at the sample can be applied with confidence to the adjacent section of reactor vessel, the maximum vessel exposure will be obtained from the measured sample exposure by appropriate application of the calculated azimuthal neutron flux variation.

At uprated conditions, the maximum integrated fast neutron (E>1 Mev) exposure of the vessel was computed to be ~~6.377~~ 9.86 x 10^{19} n/cm^2 at the end of the extended license terms of ~~48~~ 72 EFPY*, approximately (Reference 6). Under the same conditions, the maximum vessel exposure at the limiting circumferential vessel weld is predicted to be ~~5.739~~ 9.86 x 10^{19} n/cm^2 at the end of the extended license terms of ~~48~~ 72 EFPY*, approximately (Reference 6)**. The predicted extended end of life RT(ndt) is less than the 10CFR50.61 screening criteria (Reference 6).

To evaluate the RT(ndt) shift of welds, heat affected zones and base material for the vessel, test coupons of these material types have been included in the reactor vessel surveillance program described in Section 4A.

* This value is approximate and will change from year to year based on the unit availability. Fluence prediction is acceptable in the ±20% range, so this value can easily vary within that limit.

** After the (hafnium) pressurized thermal shock absorbers were removed from the vessel cores in 2009, the maximum vessel exposure at the limiting circumferential weld is predicted to be ~~5.739~~ 9.86 x 10^{19} n/cm^2 at the end of the extended license terms of approximately ~~48~~ 72 EFPY (Reference 6). The NRC was notified of this proposed change as captured in Reference 9. The NRC approved the changes as documented in Reference 12.

4.2.13 REFERENCES

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This use of these stress criteria for this abnormal operation is consistent with the ASME Boiler and Pressure Vessel Code, Section III Nuclear Vessels, paragraph N-414.1, N-414.2, and N-414.3 stress criteria. The stresses and stress factors in the actual tube sheet, obtained using the above stress criteria, are given in Table 4.3-3.

The tube sheet designed on the above basis meets code allowable stresses for a primary to secondary differential pressure of 1700 psi. The maximum normal operating differential pressure is 1549 psi.

The tubes have been designed to the requirements (including stress limitations) of Section III for normal operation, assuming 2485 psi as the normal operating pressure differential. Hence, the secondary pressure loss accident condition imposes no extraordinary stress on the tubes beyond that normally expected and considered in Section III requirements.

No significant corrosion of the Inconel tubing is expected during the lifetime of the unit. The corrosion rate reported in Reference (4) shows "worst case" rates of 15.9 mg/dm^2 in the 2000 hour test under steam generator operating conditions. Conversion of this rate to a ~~60~~80-year unit life gives a corrosion loss of less than ~~2.25~~ approximately 3.00 x 10^{-3} inches which is insignificant compared to the nominal tube wall thickness of 0.050 inches.

In the case of a primary pressure loss accident, the secondary-primary pressure differential can reach 1100 psi. This pressure differential is less than the primary-secondary pressure differential capability (1549 psi) for normal operating conditions. Hence, no stresses in excess of those covered in Section III rules for normal operation are experienced on the tube sheet for this accident case. For the tubes, actual pressure tests of 3/4 in. O.D./.058 inch wall Inconel tubing show collapse under external pressure of 5700-5900 psi. Extrapolating these data to 7/8 in. O.D./.050 inch wall tubes, collapse would occur at about 2630 psi at 650°F. This gives a factor of safety of 2.4 against collapse under the 1100 psig accidental application of external pressure to tubes. The ASME Section VIII design curves for Iron-Chromium-Nickel Steel cylinders under external pressure indicate a predicted collapse pressure for the tubes of 2310 psi, which checks closely with the extrapolated value for the experimental results.

UFSAR Chapter 5 Changes

A containment structure re-analysis was completed in 1994 and Safety Evaluation JPN-PTN-SECJ-94-027 (Reference 9) has been performed to document the results of this re-analysis.

The containment re-analysis used a three dimensional (3-D) finite element model of the containment structure. The 3-D model consisted of the cylindrical wall (including buttresses), ring girder, dome, base slab, and the major penetrations (equipment hatch and personnel hatch). The containment re-analysis did not include a new evaluation of the base slab since it was not affected by the post-tensioning system. The base slab was included in the 3-D model to provide a realistic boundary condition for the model.

Appendix 5H provides a summary of the containment re-analysis methodology, analytical techniques, references, and results.

The portions of Sections 5.1.3 and 5.1.4 relative to the original analysis of the containment structure which are affected by the 1994 re-analysis (see Appendix 5H) are annotated in the pertinent sections.

License Renewal Analysis

During the License Renewal process, the Turkey Point Units 3 and 4 containment tendons were analyzed for a 60-year life. The analysis concluded that the containment tendons will continue to meet the licensing basis requirements through the licensed plant 60-year life. (Subsection 16.3.4)

Subsequent License Renewal Analysis

During the Subsequent License Renewal (SLR) process, the Turkey Point Units 3 and 4 containment tendons were analyzed for an 80-year life. The analysis concluded that the containment tendons will continue to meet the licensing basis requirements through the licensed plant 80-year life. (Subsection 17.3.6)

5.1.3.1 Axisymmetric Analysis (original analysis)

The finite element technique is a general method of structural analysis in which the continuous structure is replaced by a system of elements (members) connected at a finite number of nodal points (joints). Standard conventional analysis of frames and trusses can be considered to be examples of the finite element method. In the application of the method to an axisymmetric solid (e.g., a concrete containment structure) the continuous structure is replaced by a system of rings of triangular cross-section which are interconnected along circumferential joints. Based on energy principles, work equilibrium equations are formed in which the radial and axial displacements at the circumferential joints are the unknowns. The results of the solution of this set of equations is the deformation of the structure under the given loading

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Assuming that the jacking stress for the tendons is 0.80 f'_s or 192,000 psi and using the above prestress loss parameters, the following tabulation shows the magnitude of the design losses and the final effective prestress at end of 40 years for a typical dome, hoop, and vertical tendon.[5]

	Dome (Ksi)	Hoop (Ksi)	Vertical (Ksi)	Allowable (Ksi)
Temporary Jacking Stress	192	192	192	192
Friction Loss	19	21.3[1]	21	
Seating Loss	-	0	0	
Elastic Loss (average)	14.7	15.3	6.6	
Creep Loss	19.2	19.2	19.2[4]	
Shrinkage Loss	3.0	3.0	3.0	
Relaxation Loss[3]	12.5	12.5	12.5	
Final Effective Stress [2]	123.6	120.7	129.7	144.0

(1) Average of adjacent tendons

(2) This force does not include the effect of pressurization which increases the prestress force.

(3) See footnote (1) in listing at beginning of Section 5.1.4.4.

(4) To determine tendon surveillance lift-off acceptance criteria, the creep loss for the vertical tendons has been adjusted. For further details, see Reference 11 of safety evaluation JPN-PTN-SECJ-94-027 (Reference 9 on Page 5.1.3-38).

(5) The 40-year prestress losses depicted in the tabulation were utilized to calculate 60-year prestress losses for license renewal and the 80-year prestress losses for subsequent license renewal.

To provide assurance, of achievement of the desired level of Final Effective

Prestress and that ACI 318-63 requirements are met, a written procedure was prepared for guidance of post-tensioning work. The procedures provided nominal values for end anchor forces in terms of pressure gage readings for calibrated jack-gage combinations. Force measurements were made at the end anchor, of course, since that is the only practical location for such measurements.

5.1.7.4 Tendon Surveillance

Provisions are made for an in-service tendon surveillance program, throughout the life of the plant that will maintain confidence in the integrity of the containment structure. (See Subsection 16.2.1.4 for program description relating to license renewal. See Subsections 17.2.1.3 and 17.2.2.31 for the aging management programs relating to subsequent license renewal.)

The following quantity of tendons have been provided over and above the structural requirements:

Horizontal - Three 120 degree tendons comprising one complete hoop system.

Vertical - Three tendons spaced approximately 120 degrees apart.

Dome - Three tendons spaced approximately 120 degrees apart.

Prior to the twentieth year tendon surveillance, inspections and lift-off readings were performed at each surveillance period on the same tendon samples
selected originally for inspection. During the twentieth year and twenty fifth year surveillances, inspections and lift-off readings were performed on five horizontal, four vertical, and three dome tendons. The tendons chosen for surveillance were a random but representative sample.

Beginning with the thirtieth year tendon surveillance, inspections are performed on five horizontal, four vertical, and four dome tendons in accordance with the requirements of ASME Section XI, Subsection IWL, and Code of Federal Regulations 10 CFR 50.55a. The tendons chosen for surveillance are
a random sample selected in accordance with Subsection IWL.

the combination of normal loads and design earthquake loading. Critical equipment needed for this purpose is required to operate within normal design limits.

In the case of the maximum hypothetical earthquake, it is only necessary to ensure that critical components do not lose their capability to perform their safety function, i.e., shut the unit down and maintain it in a safe condition.

This capability is ensured by maintaining the stress limits as shown in Table 5A-1. No rupture of a Class I pipe is caused by the occurrence of the maximum hypothetical earthquake.

Careful design and thorough quality control during manufacture and construction and inspection during unit life, ensures that the independent occurrence of a reactor coolant pipe rupture is extremely remote. Leak-Before-Break (LBB) criteria has been applied to the reactor coolant system piping based on fracture mechanics technology and material toughness. That evaluation, together with the leak detection system, demonstrates that the dynamic effects of postulated primary loop pipe ruptures may be eliminated from the design basis (Reference 5A-2). This Leak-Before-Break evaluation was approved by the NRC for use at Turkey Point (Reference 5A-5). This evaluation has been revised for the period of extended operation, as discussed in Subsection 16.3.8. This evaluation has been revised for the subsequent period of extended operation, as discussed in Subsections 17.3.8.3, 17.3.8.4, and 17.3.8.5.

5A-1.3.2.2 Reactor Vessel Internals

5A-1.3.2.2.1 Reactor Vessel Internals Design Criteria

The internals and core are designed for normal operating conditions and subjected to load of mechanical, hydraulic, and thermal origin. The response of the structure under the design earthquake is included in this category.

The stress criteria established in the ASME Boiler and Pressure Vessel Code, Section III, have been adopted as a guide for the design of the internals and core with the exception of those fabrication techniques and materials which are not covered by the Code. Earthquake stresses are combined in the most conservative way and are considered primary stresses.

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to accommodate the forces exerted by the restrained liner plate, and that careful attention be paid to details at corners and connections to minimize the effects of discontinuities.

The most appropriate basis for establishing allowable liner plate strains is considered to be that portion of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Article 4. Specifically the following sections are adopted as guides in establishing the allowable strain limits:

Paragraph N 412 (m)	Thermal Stress
Paragraph N414.5	Peak Stress Intensity
	Table N 413
	Figure N 414, N 415 (A)
Paragraph N 412 (n)	
Paragraph N 415.1	

Implementation of the ASME Code requires that the liner material be prevented from experiencing significant distortion due to thermal load and that the stresses be considered from a fatigue standpoint. (Paragraph N412 (m) (2)).

The following fatigue loads are considered in the ~~60~~80-year design analysis of the liner plate (See Subsection ~~16.3.5~~17.3.7 for additional details):

(a) Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is ~~60~~80 cycles for the unit life of ~~60~~80 years.

(b) Thermal cycling due to the containment interior temperature variation during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500 cycles.

(c) Thermal cycling due to the MHA will be assumed to be one cycle.

(d) Thermal load cycles in the piping systems are somewhat isolated from the liner plate penetrations by the concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Section III fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the ~~60~~80-year unit life.

The thermal stresses in the liner plate fall into the categories considered in Article 4, Section III, of the ASME Boiler and Pressure Vessel Code. The allowable stresses in Figure N-415 (A) are for alternating stress intensity for carbon steel and temperatures not exceeding 700°F.

In accordance with ASME Code Paragraph N412 (m) 2, the liner plate is restrained against significant distortion by continuous angle anchors and never exceeds the temperature limitation of 700°F and also satisfies the criteria for limiting strains on the basis of fatigue consideration. Paragraph N412 (n) Figure N-415 (A) of the ASME Code has been developed as a result of research, industry experience, and the proven performance of code vessels, and it is a part of recognized design code. Figure N-415 (A) and its appropriate limitations have been used as a basis for establishing allowable liner plate strains. Since the graph in Figure N-415 (A) does not extend below 10 cycles, 10 cycles is being used for MHA instead of one cycle.

The maximum compressive strains are caused by accident pressure, thermal loading prestress, shrinkage and creep. The maximum strains do not exceed .0025 in/in and the liner plate always remains in a stable condition.

UFSAR CHAPTER 6 CHANGES

6.3.6 MOTORS FOR EMERGENCY CONTAINMENT FANS

General

These totally enclosed fan cooled motors will have a useful life of eighty ~~sixty (60)~~ years under the normal containment service conditions as demonstrated by the appropriate EQ documentation package (See Appendix 8A). Internal heaters will dispel moisture condensation when motor is idle, with one exception. The fan motors, power cables and control circuits for the Unit 3 and 4 emergency containment filter units 3V3A, 3V3A, 3V3B, 3V3C, 4V3A, 4V3b, 4V3c were disconnected and abandoned in place, and the control switches were removed from the control room.

Insulation

The insulation will be a special Class B suitable for MHA conditions. The insulation system is described in Table 6.3-2.

Bearings

The bearings will be specially selected, conservatively rated ball bearings with clearances, held to closer tolerances than standard bearings.

The lubricant will be a high temperature, radiation resistant grease listed in Table 6.3-2.

The bearing housing will be so constructed that a sudden pressure wave will in no way impair the lubrication or serviceability of the bearings.

Qualification of materials is stated in Section 6.7.

6.3.7 REFERENCES

1. Turkey Point Units 3 and 4 - Issuance of Amendments Regarding Alternative Source Term (Tac Nos. ME 1624 and ME 1625), Issued June 23, 2011, ML 110800666.

UFSAR CHAPTER 8 CHANGES

Environments in which radiation is the only parameter of concern are considered to be mild if the total radiation dose (includes ~~60~~80-year normal dose plus the post accident dose) is 1.0E5 rads or less. This value is the threshold for evaluation and consideration based on EPRI NP-2129. However, certain solid state electronic components and components that utilize teflon are considered to be in a mild environment only if total radiation dose is 1.0E3 rads or less.

For additional detail on the identification of environmental conditions refer to Equipment Qualification Documentation Package (Doc Pac) 1001, "Generic Approach and Treatment of Issues."

8A.5 MAINTENANCE

The purpose of the Turkey Point Equipment Qualification Maintenance Program is the preservation of the qualification of systems, structures and components. In order to accomplish this task, the plants have developed approved Design Control, Procurement and Maintenance Procedures. In addition, the component specific documentation package contains the equipment's qualified life. The qualified life is developed based upon the qualification test report reviewed in conjunction with the environmental parameters associated with the area. After this review is completed a qualified life is established. Maintenance activities to be performed in addition to the vendor recommended maintenance are determined to ensure that qualification of each piece of equipment is maintained throughout its qualified life.

8A.6 RECORDS/QUALITY ASSURANCE

A documentation package is prepared for the qualification of each manufacturer's piece of equipment under the auspices of 10CFR50.49. This package contains the information, analysis and justifications necessary to demonstrate that the equipment is properly and validly qualified as defined in 10CFR50.49 for the environmental effects of ~~60~~80 years of service plus a design basis accident.

This documentation package is developed from the criteria stipulated in Doc Pac 1001.

A complete listing of equipment under the auspices of 10CFR50.49 is maintained.

UFSAR CHAPTER 9 CHANGES

TABLE 9.2-2

NOMINAL CHEMICAL AND VOLUME CONTROL SYSTEM PERFORMANCE [1]

Unit design life, years	80~~60~~
Seal water supply flow rate, gpm [2]	24
Seal water return flow rate, gpm	7.5
Normal letdown flow rate, gpm	60
Maximum letdown flow rate, gpm	120
Normal charging pump flow (one pump), gpm 69	
Normal charging line flow, gpm 45	
Maximum rate of boration with one transfer and one charging pump from an initial RCS concentration of 1800 ppm, ppm/min	6.5
Equivalent cooldown rate to above rate of boration, °F/min	1.5
Maximum rate of boron dilution with two charging pumps from an initial RCS concentration of 2500 ppm, ppm/hour	350
Two-pump rate of boration, using refueling water, from initial RCS concentration of 10 ppm, ppm/min[3]	6.2
Equivalent cooldown rate to above rate of boration, °F/min	1.4
Temperature of reactor coolant entering system at full power (design), °F	555.0
Temperature of coolant return to reactor coolant system at full power (design), °F	493.0
Normal coolant discharge temperature to holdup tanks, °F	127.0
Amount of 3.0 weight percent boron solution required to meet cold shutdown requirements, at end of life with peak xenon (including consideration for one stuck rod). This value is based on a usable volume of 10,275 gallons plus 900 gallons volumetric uncertainty.	11,175

NOTES :
1. Reactor coolant water quality is given in Table 4.2-2.
2. Volumetric flow rates in gpm are based on 130°F and 2350 psig.
3. 6.2 ppm/min remains a bounding minimum boration rate for two pumps at EPU conditions

Rev.[LATER]~~ised 08/03/2016~~

UFSAR CHAPTER 11 CHANGES

TABLE 11.1-1

WASTE DISPOSAL SYSTEM
PERFORMANCE DATA
(Two Units)

Plant Design Life	~~60~~ 80 years
Normal process capacity, liquids	Table 11.1-3
Evaporator load factor	Table 11.1-4
Annual liquid discharge	
Volume	Table 11.1-4
Activity	
Tritium	Table 11.1-5
Other	Table 11.1-5
Annual gaseous discharge	
Activity	Table 11.1-6

Rev.[LATER]~~06/26/2002~~

Appendix B

Aging Management Programs

Turkey Point Nuclear Plant Units 3 and 4
Subsequent License Renewal Application

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B.1 INTRODUCTION

B.1.1 OVERVIEW

The Subsequent License Renewal (SLR) Aging Management Program (AMP) descriptions are provided in this appendix for each program credited for managing aging effects based upon the Aging Management Review (AMR) results provided in Sections 3.1 through 3.6 of this Subsequent License Renewal Application (SLRA).

In general, there are four types of AMPs:

- Prevention programs that preclude aging effects from occurring.
- Mitigation programs that slow the effects of aging.
- Condition monitoring programs that inspect/examine for the presence and extent of aging.
- Performance monitoring programs that test the ability of a structure or component to perform its intended function.

More than one type of AMP may be implemented for systems, structures, and components (SSCs) to ensure that aging effects are managed.

Part of the demonstration that the effects of aging are adequately managed is to evaluate credited programs and activities against certain required attributes. Each of the AMPs described in this section has 10 elements, which are consistent with the attributes described in Table 2, "Aging Management Programs Element Descriptions," of NUREG-2191 (Reference B.3.9), *Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report.*

Please note that existing PTN license renewal programs are considered to be "pre-GALL," although many of these existing programs included the required SLR 10-element attributes and have been demonstrated to adequately manage the identified aging effects during the PEO. If an existing program does not adequately manage an identified aging effect, then the finding is entered into the Corrective Action Program (CAP) and the program is enhanced, as necessary.

Credit has been taken for these existing PTN programs whenever possible. In this regard, existing PTN programs and activities associated with in-scope SLR SSCs have been evaluated in preparing the SLRA to determine whether they include the necessary actions to manage the effects of aging consistent with the current revision of NUREG-2191. However, some existing PTN programs aligned with multiple NUREG-2191 AMPs, and some NUREG-2191 AMPs aligned with multiple PTN programs. Therefore, the existing PTN AMPs to be continued for SLR will be renamed as applicable to align with the NUREG-2191 AMP names. New PTN AMPs align with the NUREG-2191 AMP names. Enhancements to existing PTN AMPs are made as needed to meet GALL-SLR. Consistent with this approach, the following new aging management programs will be created at PTN for purposes of SLR:

- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP (Section B.2.3.6)
- One-Time Inspection AMP (Section B.2.3.20)
- Selective Leaching AMP (Section B.2.3.21)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (Section B.2.3.25)
- Buried and Underground Piping and Tanks AMP (Section B.2.3.28)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.29)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP (Section B.2.3.38)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.40)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP (Section B.2.3.41)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP (Section B.2.3.42)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP (Section B.2.3.43)
- High-Voltage Insulators AMP (Section B.2.3.44)

The new AMPs listed above will be consistent with NUREG-2191, without exception. The AMPs listed below will also be consistent with the 10 elements of their respective NUREG-2191 AMPs, but have one exception justified by technical data:

- Reactor Head Closure Stud Bolting AMP (Section B.2.3.3)
- Steam Generators (Section B.2.3.10)
- Closed Treated Water Systems AMP (Section B.2.3.12)
- Fuel Oil Chemistry AMP (Section B.2.3.18)

- ASME Section XI, Subsection IWF AMP (Section B.2.3.32)
- Structures Monitoring AMP (Section B.2.3.35)

PTN is actively managing its current AMPs and programs during the current PEO but seeks to confirm the effective implementation of its AMPs and to identify areas for further program improvements that will heighten the effectiveness of aging management both now and during the SPEO. Consequently, PTN conducted a License Renewal AMP Effectiveness Review to identify gaps related to the effectiveness of the current PTN license renewal AMPs in accordance with NEI 14-12, Revision 0, “Aging Management Program Effectiveness.” This effectiveness review was completed in December 2017 and included all active AMPs referenced in the UFSAR as managing the effects of aging for the renewed operating license, with the exception of the Containment Cable Inspection Program due to the fact it is a one-time inspection which will occur in the future. The scope of this effectiveness review thus included 17 current PTN AMPs.

The effectiveness review was conducted by program personnel and was reviewed by the applicable supervisor and a member of the Renewed License Program Peer Team. The individual AMPs were reviewed against the performance criteria set forth in Section 4.0 of NEI 14-12 (Reference B.3.84), which provide a standard approach to the review based on the 10 Program Elements which define an Aging Management Program as set forth in NUREG-2191. Any criterion which was not met was identified as a “gap.” The gaps pertaining to each of the 10 Program Elements applicable to a particular AMP were evaluated comprehensively to determine whether the combined gaps, if left uncorrected, would result in a “failed program element,” or were primarily administrative in nature.

Specifically, Program Elements were considered to be “failed” if the combination of identified gaps could have prevented the effective implementation of the associated Program Element. Program Elements were not considered to be “failed” if the gap identified an administrative error that would not prevent the Program Element’s effective implementation or did not have a significant consequence. For the purposes of this review, an AMP was deemed to be “ineffective” if it failed to meet one or more of the five attributes of an effective program described in NEI 14-12:

- Commitments are managed in accordance with NEI 99-04 and NRC RIS 2000-017.
- Aging management program implementing activities are completed as scheduled.
- Industry and site-specific operating experience is routinely evaluated and program adjustments are made as necessary.
- Self-assessments are conducted and program adjustments are made as necessary.
- No significant findings are identified from external assessments (e.g., NRC) or internal audits.

In addition to failing to meet one or more of the five effective program attributes listed above, an "ineffective" program also would have:

- One or more failed Program Elements; and
- Gaps (associated with the failed element(s)) that if not identified and corrected had a high probability of eventually allowing the loss of SSC function.

A summary of results from the PTN License Renewal AMP Effectiveness Review follows below. However, program-specific details for those with failed elements are provided in the individual AMP summaries that are set forth in the remainder of Appendix B.

Turning first to program effectiveness—the review concluded that only one AMP was ineffective at PTN: Systems and Structures Monitoring program (Systems Monitoring Program and Structures Monitoring program are sub-parts of this program). The existing Systems and Structures Monitoring program was concluded to be "ineffective" at managing the effects of aging because of not meeting Attribute 2 of an effective program described in NEI 14-12 and two failed elements were identified by the review team related to timeliness of initial and follow up evaluations and inspections. This is discussed more fully in the remainder of Appendix B.

However, as part of the self-assessment process, it was determined that, the program's ineffectiveness did not result in overarching programmatic inadequacy because the failures identified above, neither individually nor collectively, has caused or resulted in, a loss of intended function of any SSCs included in the scope of the program to date. In response to the Effectiveness Review findings, PTN initiated corrective actions. The corrective actions are being implemented and tracked to completion in a timely fashion to provide reasonable assurance that loss of intended function will not occur in the future. As a result, the existing Systems and Structures Monitoring program is effective at PTN, as further discussed in Section B.2.3.35.

In addition, the five SPEO programs listed below are also currently encompassed by the existing Systems and Structures Monitoring program in whole or in part. Thus, the Effectiveness Review findings pertaining to that program as set forth above also are potentially applicable to these five additional SPEO programs and are fully discussed in the AMP program descriptions that follow in the remainder of Appendix B for:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP (Section B.2.3.13).
- External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23).
- Masonry Walls AMP (Section B.2.3.34).
- Structures Monitoring AMP (Section B.2.3.35).

- Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP (Section B.2.3.36).

Next, PTN has fully considered and addressed through the CAP, the License Renewal Effectiveness Review findings pertaining to “failed elements” that did not culminate in ineffective program-level findings. Note that none of the “failed elements,” individually or collectively attributed to the programs listed below would have resulted in a loss of intended function in the SSCs included in their scope. Specifically, the following AMPs were determined to be effective, but had certain failed element findings resulting from the Effectiveness Review, as more fully discussed in each AMP summary:

- Thimble Tube Monitoring AMP (see Section B.2.3.24, Flux Thimble Tube Inspection AMP)

- Containment Spray Piping Inspection AMP (see Section B.2.3.25, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP)

- Auxiliary Feedwater Steam Piping Inspection AMP (see Section B.2.3.8, Flow-Accelerated Corrosion AMP)

- Fire Protection AMP (see Section B.2.3.15, Fire Protection AMP, and Section B.2.3.16, Fire Water System AMP).

A License Renewal Effectiveness Review will be performed in 2018 for the existing AMPs identified as having failed elements as part of the recent Effectiveness Review conducted per NEI 14-12. In addition, all PTN AMPs will be subject to periodic assessment, per NEI 14-12, to ensure continued effectiveness throughout the SPEO.

B.1.2 METHOD OF DISCUSSION

For those PTN AMPs that are consistent with the AMP descriptions and assumptions made in Sections X and XI of NUREG-2191, or are consistent with exceptions or enhancements, each AMP discussion is presented in the following format:

- A Program Description abstract of the overall program form and function is provided. This Program Description also includes whether the program is existing (and if it replaces a license renewal (LR) program) or new for SLR.

- A NUREG-2191 Consistency Statement is made about the AMP.

- Exceptions to the NUREG-2191 program are outlined, and a justification for the exception(s) is provided.

- Enhancements or additions (including new surveillances/inspections) to make the PTN AMP consistent with the respective NUREG-2191 AMP are provided. A proposed schedule for completion is discussed. This SLRA defines “enhancements” as any changes to plant programs or activities that need to be implemented in order to align with the guidance of NUREG-2191.

- Operating Experience (OE) information specific to the AMP is provided.
- A Conclusion section provides a statement of reasonable assurance that the PTN AMP for SLR is effective, or will be effective when implemented (if new or enhanced).

For the one PTN site-specific AMP, the PTN Pressurizer Surge Line Fatigue AMP (Section B.2.4.1), a complete discussion of the 10 elements of NUREG-2191, Table 2, is provided.

B.1.3 QUALITY ASSURANCE PROGRAM AND ADMINISTRATIVE CONTROLS

The FPL Quality Assurance (QA) Program (Reference B.3.145) for PTN implements the requirements of 10 CFR Part 50, Appendix B, “Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants,” and is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1),” of NUREG-2192. The FPL QA Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related SSCs and commodity groups that are included within the scope of the AMPs. Generically, the three elements are applicable as follows.

Corrective Actions

A single PTN CAP is applied regardless of the safety classification of the SSC or commodity group. The PTN CAP requires the initiation of a Condition Report (CR) for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction, or loss of function. Site documents that implement AMPs for SLR direct that a CR be prepared in accordance with those procedures whenever non-conforming conditions are found (i.e., the acceptance criteria are not met). Equipment deficiencies are corrected through the work control process in accordance with plant procedures. The PTN CAP specifies that for equipment deficiencies a CR be initiated for condition identification, assignment of significance level and investigation class, investigation, corrective action determination, investigation report review and approval, action tracking, and trend analysis.

The following statement applies to all the PTN AMPs for SLR:

> *Conditions adverse to quality (such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconforming conditions) are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the condition is determined and that corrective action is taken to preclude recurrence. The root cause of any significant condition adverse to quality, and the corrective action implemented, is documented and reported to*

appropriate levels of management. The corrective action controls of the Florida Power & Light Company (FPL) Quality Assurance Program as described in FPL-1, Quality Assurance Topical Report, will be used to meet Element 7, Corrective Actions, of each AMP credited for SLR.

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 PTN CAP includes provisions for timely evaluation of adverse conditions and implementation of corrective actions required, including root cause determinations and prevention of recurrence where appropriate (e.g., significant conditions adverse to quality). The PTN CAP provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The PTN CAP also includes monitoring for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions results in the initiation of a CR. The AMPs required for SLR would also result in identification of related unsatisfactory conditions due to ineffective corrective action.

Since the same 10 CFR Part 50, Appendix B, corrective actions and confirmation process is applied for nonconforming safety-related and nonsafety-related SSCs subject to AMR for SLR, the CAP is consistent with the NUREG-2191 and NUREG-2192 elements.

The following statement is applicable to all the PTN AMPs for SLR:

Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The FPL Quality Assurance Program as described in FPL-1, Quality Assurance Topical Report, will be used to meet Element 8, Confirmation Process, for each AMP credited for SLR. The confirmation process is part of the CAP and includes the following:

- *Reviews to ensure that proposed corrective actions are adequate*
- *Tracking and reporting of open corrective actions*
- *Review of corrective action effectiveness*

Any follow-up inspection required by the confirmation process is documented in accordance with the CAP. The CAP constitutes the confirmation process for PTN aging management programs and activities.

Administrative Controls

The document control process applies to all generated documents, procedures, and instructions regardless of the safety classification of the associated SSC or commodity group. Document control processes are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. Administrative controls procedures provide information on procedures, instructions and other forms of administrative control documents, as well as guidance on classifying these documents into the proper document type and as-building frequency. Revisions will be made to procedures and instructions that implement or administer AMP requirements for the purposes of managing the associated aging effects for the subsequent period of extended operation (SPEO).

The following statement is applicable to all the PTN AMPs for SLR:

> *Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The FPL Quality Assurance Program as described in FPL-1, Quality Assurance Topical Report, will be used to meet Element 9, Administrative Controls, for each AMP credited for SLR.*

B.1.4 OPERATING EXPERIENCE

NUREG-2192 (Reference B.3.10), Appendix A.4.2, provides guidance to ensure that the programmatic activities for the ongoing review of OE are adequate for SLR, and identifies ten points for further review. This section discusses how the PTN OE process addresses the ten points, and summarizes further actions to enhance the OE process where it does not fully meet the guidance. The enhancements, which are listed numerically at the end of this section, will be incorporated into the PTN OE program (part of the FPL fleet OE program) and implemented no later than the date when the subsequent operating license is issued. These actions will ensure that the internal and external OE related to aging management is used effectively throughout the SPEO.

The following information addresses NUREG-2192, Appendix A.4.2 points 1 and 7. Internal OE (also referred to as site-specific OE) and external OE (also referred to as industry OE) sources are captured and systematically reviewed on an ongoing basis in accordance with the FPL QA Program and the PTN OE program. Corrective actions being taken as a result of the License Renewal AMP Effectiveness Review performed in December 2017 and documented in Section B.1.1 will further ensure that Internal OE and external OE sources are captured and systematically reviewed on an ongoing basis. The PTN OE program meets the requirements of NUREG-0737 (Reference B.3.6), "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." The PTN OE program also meets the requirements of NEI 14-12 (Reference B.3.84), "Aging Management Program Effectiveness" for periodic program assessments. The scope of the FPL QA program (Reference B.3.145) currently includes nonsafety-related SCs, as described in Section B.1.3.

The following information addresses NUREG-2192, Appendix A.4.2 points 3 and 9. OE is used at PTN Units 3 and 4 to enhance existing programs and AMPs, prevent repeat events, and prevent events that have occurred at other plants. As part of the FPL fleet, PTN Units 3 and 4 receive OE (internal and external to FPL) daily. The OE process screens, evaluates, and acts on OE documents and information to prevent or mitigate the consequences of similar events. The OE process reviews OE from external and internal sources, including OE related to age-related degradation or impacts to aging management activities. In addition, FPL also reports site-specific OE on age-related degradation and aging management through participation in industry OE programs. External OE includes NRC documents (e.g., Information Notices (IN), Regulatory Issue Summaries (RIS), Interim Staff Guidance (ISG)), and other industry documents (e.g., Licensee Event Reports (LER) and 10 CFR Part 21 Reports). Internal OE includes event investigations, trending reports, and lessons learned from in-house events as captured in program health reports, assessments, and in the PTN CAP, which is in accordance with 10 CFR Part 50, Appendix B. Program health reports are scored GREEN (excellent), WHITE (needs improvement), YELLOW (not acceptable), and RED (intolerable). Existing AMPs have an established performance feedback mechanism in place by requiring the OE program to evaluate both internal and external OE for applicability through entry into the CAP. This process provides reasonable assurance that AMPs are informed and enhanced, if necessary, by relevant OE. PTN meets the requirements of NEI 14-13 (Reference B.3.85) regarding the use of industry OE for AMPs.

Each AMP summary in this appendix contains a discussion of OE relevant to the AMP. This information was obtained through the review of internal OE captured by the PTN CAP, program assessments, program health reports, and through the review of external OE. Additionally, to provide assurance that OE was fully understood and discussed, interviews were performed with system engineers, program engineers, and other plant personnel. New AMPs utilize internal and/or external OE, as applicable, and discuss the OE and associated corrective actions as they relate to implementation of the new AMP. The OE in each AMP summary identifies past corrective actions that have resulted in program enhancements. The AMP summary also identifies any ongoing corrective actions related to OE identified as a result of the effectiveness reviews. This 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 AMP will be maintained during the SPEO.

As described above, the existing OE process at PTN, in conjunction with the PTN CAP, has proven to be effective in learning from adverse conditions and events, and improving programs that address age-related degradation.

The following information addresses NUREG-2192, Appendix A.4.2 points 2, 4, 5, 6 and 8. In order to provide additional assurance that internal and external OE related to aging management is used effectively during the SPEO, PTN will enhance its OE program as follows:

1. PTN currently assigns review of NRC regulatory guidance as a responsibility of the AMP coordinator, and specifies LR-ISGs as requiring periodic review as external OE. The OE program also lists LR-ISGs as screened items for OE. In order to further enhance the OE program, PTN will specify that SLR-ISGs and GALL-SLR revisions are required OE review items.

2. The PTN OE program ensures the effectiveness of license renewal aging management programs through ongoing reviews of relevant OE. In order to further enhance the OE

program, PTN will develop an aging management trend code and specify a requirement to perform OE trending for aging management related degradation within the CAP.

3. The PTN OE program currently requires an evaluation to be performed if screening of internal/external OE indicates potential applicability to PTN. Recently, the program has been updated to include vendor documents received (EPRI, PWROG, etc.) as a result of research and development, which are submitted for evaluation in the CAP. If screening of internal/external OE identifies prompt action for determination of applicability and potential gaps, this information is communicated and documented in accordance with PTN procedures. Evaluations and corrective actions associated with the PTN OE program are tracked and maintained in the CAP. In order to further enhance the PTN OE program, PTN will specify evaluation of OE for the aging management-related criteria included in the following items:

    a. SSCs

    b. Materials

    c. Environments

    d. Aging effects

    e. Aging mechanisms

    f. AMPs

    g. Activities, criteria, and evaluations integral to the elements of the AMPs

4. PTN currently requires AMP owner training whenever there is turnover with AMP owner personnel. In order to further enhance the training, PTN will provide training to those responsible for screening, evaluating, and communicating operating experience items related to aging management and aging-related degradation. This training will be commensurate with their role in the process, will be provided periodically, and will continue to include provisions to accommodate personnel turnover.

The following information addresses NUREG-2192, Appendix A.4.2 point 10. The enhancements listed above will be implemented no later than the date the subsequent operating license is issued and implemented on an ongoing basis throughout the SPEO. These actions will ensure that the internal and external OE related to aging management is used effectively during the SPEO.

B.1.5 AGING MANAGEMENT PROGRAMS

Table B-1 lists the PTN AMPs for SLR in the order that their respective AMP appeared in NUREG-2191 (Reference B.3.9). Table B-1 states the respective AMP section numbers and whether the AMP is considered a new program or an existing program (or a portion of an existing program) at PTN. Existing AMPs are based on either an existing LR AMP or existing plant program. Additionally, Table B-2 lists the PTN AMPs for SLR in alphabetical order. All the AMPs either are or will be consistent with their respective AMPs discussed in NUREG-2191 unless otherwise noted as an exception.

Table B-1
List of PTN Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
X.M1	B.2.2.1	Fatigue Monitoring	Existing
X.M2	B.2.2.2	Neutron Fluence Monitoring	Existing
X.S1	B.2.2.3	Concrete Containment Unbonded Tendon Prestress	Existing
X.E1	B.2.2.4	Environmental Qualification of Electric Equipment	Existing
XI.M1	B.2.3.1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing
XI.M2	B.2.3.2	Water Chemistry	Existing
XI.M3	B.2.3.3	Reactor Head Closure Stud Bolting	Existing
XI.M4	N/A	BWR Vessel ID Attachment Welds Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M5	N/A	Not Applicable (Deleted from NUREG-2191)	N/A
XI.M6	N/A	Not Applicable (Deleted from NUREG-2191)	N/A
XI.M7	N/A	BWR Stress Corrosion Cracking Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M8	N/A	BWR Penetrations Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M9	N/A	BWR Vessel Internals Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M10	B.2.3.4	Boric Acid Corrosion	Existing
XI.M11B	B.2.3.5	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	Existing
XI.M12	B.2.3.6	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	New
XI.M16A	B.2.3.7	Reactor Vessel Internals	Existing
XI.M17	B.2.3.8	Flow-Accelerated Corrosion	Existing
XI.M18	B.2.3.9	Bolting Integrity	Existing

Table B-1
List of PTN Aging Management Programs (Continued)

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.M19	B.2.3.10	Steam Generators	Existing
XI.M20	B.2.3.11	Open-Cycle Cooling Water System	Existing
XI.M21A	B.2.3.12	Closed Treated Water Systems	Existing
XI.M22	N/A	Boraflex Monitoring Not Applicable (PTN U3 and U4 do not credit Boraflex as a neutron absorber in their criticality analyses.)	N/A
XI.M23	B.2.3.13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Existing
XI.M24	B.2.3.14	Compressed Air Monitoring	Existing
XI.M25	N/A	BWR Reactor Water Cleanup System Not Applicable (PTN U3 and U4 are PWRs)	N/A
XI.M26	B.2.3.15	Fire Protection	Existing
XI.M27	B.2.3.16	Fire Water System	Existing
XI.M29	B.2.3.17	Outdoor and Large Atmospheric Metallic Storage Tanks	Existing
XI.M30	B.2.3.18	Fuel Oil Chemistry	Existing
XI.M31	B.2.3.19	Reactor Vessel Material Surveillance	Existing
XI.M32	B.2.3.20	One-Time Inspection	New
XI.M33	B.2.3.21	Selective Leaching	New
XI.M35	B.2.3.22	ASME Code Class 1 Small-Bore Piping	Existing
XI.M36	B.2.3.23	External Surfaces Monitoring of Mechanical Components	Existing
XI.M37	B.2.3.24	Flux Thimble Tube Inspection	Existing
XI.M38	B.2.3.25	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	New
XI.M39	B.2.3.26	Lubricating Oil Analysis	Existing
XI.M40	B.2.3.27	Monitoring of Neutron-Absorbing Materials other than Boraflex	Existing
XI.M41	B.2.3.28	Buried and Underground Piping and Tanks	New
XI.M42	B.2.3.29	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	New
XI.S1	B.2.3.30	ASME Section XI, Subsection IWE	Existing
XI.S2	B.2.3.31	ASME Section XI, Subsection IWL	Existing

Table B-1
List of PTN Aging Management Programs (Continued)

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.S3	B.2.3.32	ASME Section XI, Subsection IWF	Existing
XI.S4	B.2.3.33	10 CFR Part 50, Appendix J	Existing
XI.S5	B.2.3.34	Masonry Walls	Existing
XI.S6	B.2.3.35	Structures Monitoring	Existing
XI.S7	B.2.3.36	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing
XI.S8	B.2.3.37	Protective Coating Monitoring and Maintenance	Existing
XI.E1	B.2.3.38	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Existing
XI.E2	B.2.3.39	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	New
XI.E3A	B.2.3.40	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E3B	B.2.3.41	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E3C	B.2.3.42	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E4	N/A	Metal Enclosed Bus Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E5	N/A	Fuse Holders Not Applicable (PTN U3 and U4 do not have any components within this program scope.)	N/A
XI.E6	B.2.3.43	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E7	B.2.3.44	High-Voltage Insulators	New
N/A – PTN Site-Specific Program	B.2.4.1	Pressurizer Surge Line Fatigue	Existing

Table B-2
Aging Management Programs

PTN Aging Management Program	Section	NUREG-2191 Section
10 CFR Part 50, Appendix J	B.2.3.33	XI.S4
ASME Code Class 1 Small-Bore Piping	B.2.3.22	XI.M35
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B.2.3.1	XI.M1
ASME Section XI, Subsection IWE	B.2.3.30	XI.S1
ASME Section XI, Subsection IWF	B.2.3.32	XI.S3
ASME Section XI, Subsection IWL	B.2.3.31	XI.S2
Bolting Integrity	B.2.3.9	XI.M18
Boric Acid Corrosion	B.2.3.4	XI.M10
Buried and Underground Piping and Tanks	B.2.3.28	XI.M41
Closed Treated Water Systems	B.2.3.12	XI.M21A
Compressed Air Monitoring	B.2.3.14	XI.M24
Concrete Containment Unbonded Tendon Prestress	B.2.2.3	X.S1
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	B.2.3.5	XI.M11B
Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.43	XI.E6
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.38	XI.E1
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	B.2.3.39	XI.E2
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.41	XI.E3B
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.42	XI.E3C
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.40	XI.E3A
Environmental Qualification of Electric Equipment	B.2.2.4	X.E1

Table B-2
Aging Management Programs (Continued)

PTN Aging Management Program	Section	NUREG-2191 Section
External Surfaces Monitoring of Mechanical Components	B.2.3.23	XI.M36
Fatigue Monitoring	B.2.2.1	X.M1
Fire Protection	B.2.3.15	XI.M26
Fire Water System	B.2.3.16	XI.M27
Flow-Accelerated Corrosion	B.2.3.8	XI.M17
Flux Thimble Tube Inspection	B.2.3.24	XI.M37
Fuel Oil Chemistry	B.2.3.18	XI.M30
High-Voltage Insulators	B.2.3.44	XI.E7
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.25	XI.M38
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.3.13	XI.M23
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.36	XI.S7
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.29	XI.M42
Lubricating Oil Analysis	B.2.3.26	XI.M39
Masonry Walls	B.2.3.34	XI.S5
Monitoring of Neutron-Absorbing Materials other than Boraflex	B.2.3.27	XI.M40
Neutron Fluence Monitoring	B.2.2.2	X.M2
One-Time Inspection	B.2.3.20	XI.M32
Open-Cycle Cooling Water System	B.2.3.11	XI.M20
Outdoor and Large Atmospheric Metallic Storage Tanks	B.2.3.17	XI.M29
Pressurizer Surge Line Fatigue	B.2.4.1	N/A PTN Site-Specific
Protective Coating Monitoring and Maintenance	B.2.3.37	XI.S8
Reactor Vessel Internals	B.2.3.7	XI.M16A
Reactor Head Closure Stud Bolting	B.2.3.3	XI.M3
Reactor Vessel Material Surveillance	B.2.3.19	XI.M31
Selective Leaching	B.2.3.21	XI.M33

Table B-2
Aging Management Programs (Continued)

PTN Aging Management Program	Section	NUREG-2191 Section
Steam Generators	B.2.3.10	XI.M19
Structures Monitoring	B.2.3.35	XI.S6
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	B.2.3.6	XI.M12
Water Chemistry	B.2.3.2	XI.M2

B.2 Aging Management Programs

B.2.1 NUREG-2191 AGING MANAGEMENT PROGRAM CORRELATION

The correlation between the programs in NUREG-2191, *Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report*, (Reference B.3.9) and the PTN AMPs is shown below in Tables B-3 and B-4. Links to the sections describing the PTN NUREG-2191 programs are provided.

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	PTN Aging Management Program
X.M1	Fatigue Monitoring	Fatigue Monitoring (Section B.2.2.1)
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring (Section B.2.2.2)
X.S1	Concrete Containment Unbonded Tendon Prestress	Concrete Containment Unbonded Tendon Prestress (Section B.2.2.3)
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (Section B.2.2.4)
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.3.1)
XI.M2	Water Chemistry	Water Chemistry (Section B.2.3.2)
XI.M3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting (Section B.2.3.3)
XI.M4	BWR Vessel ID Attachment Welds	Not Applicable (PTN U3 and U4 are PWRs)
XI.M5	Deleted	Not Applicable (Deleted from NUREG-2191)
XI.M6	Deleted	Not Applicable (Deleted from NUREG-2191)
XI.M7	BWR Stress Corrosion Cracking	Not Applicable (PTN U3 and U4 are PWRs)
XI.M8	BWR Penetrations	Not Applicable (PTN U3 and U4 are PWRs)
XI.M9	BWR Vessel Internals	Not Applicable (PTN U3 and U4 are PWRs)
XI.M10	Boric Acid Corrosion	Boric Acid Corrosion (Section B.2.3.4)
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (Section B.2.3.5)
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (Section B.2.3.6)

Table B-3
Correlation with NUREG-2191 Aging Management Programs (Continued)

NUREG-2191 Section	NUREG-2191 Aging Management Program	PTN Aging Management Program
XI.M16A	PWR Vessel Internals	Reactor Vessel Internals (Section B.2.3.7)
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (Section B.2.3.8)
XI.M18	Bolting Integrity	Bolting Integrity (Section B.2.3.9)
XI.M19	Steam Generators	Steam Generators (Section B.2.3.10)
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (Section B.2.3.11)
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems (Section B.2.3.12)
XI.M22	Boraflex Monitoring	Not Applicable (PTN U3 and U4 do not credit Boraflex as a neutron absorber in their criticality analyses.)
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.2.3.13)
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring (Section B.2.3.14)
XI.M25	BWR Reactor Water Cleanup System	Not Applicable (PTN U3 and U4 are PWRs)
XI.M26	Fire Protection	Fire Protection (Section B.2.3.15)
XI.M27	Fire Water System	Fire Water System (Section B.2.3.16)
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks (Section B.2.3.17)
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry (Section B.2.3.18)
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance (Section B.2.3.19)
XI.M32	One-Time Inspection	One-Time Inspection (Section B.2.3.20)
XI.M33	Selective Leaching	Selective Leaching (Section B.2.3.21)
XI.M35	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping (Section B.2.3.22)
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components (Section B.2.3.23)
XI.M37	Flux Thimble Tube Inspection	Flux Thimble Tube Inspection (Section B.2.3.24)
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.3.25)

Table B-3
Correlation with NUREG-2191 Aging Management Programs (Continued)

NUREG-2191 Section	NUREG-2191 Aging Management Program	PTN Aging Management Program
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (Section B.2.3.26)
XI.M40	Monitoring of Neutron-Absorbing Materials other than Boraflex	Monitoring of Neutron-Absorbing Materials other than Boraflex (Section B.2.3.27)
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks (Section B.2.3.28)
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.2.3.29)
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE (Section B.2.3.30)
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL (Section B.2.3.31)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (Section B.2.3.32)
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J (Section B.2.3.33)
XI.S5	Masonry Walls	Masonry Walls (Section B.2.3.34)
XI.S6	Structures Monitoring	Structures Monitoring (Section B.2.3.35)
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B.2.3.36)
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance (Section B.2.3.37)
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 EQ Requirements (Section B.2.3.38)
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 EQ Requirements used in Instrumentation Circuits (Section B.2.3.39)
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 EQ Requirements (Section B.2.3.40)

Table B-3
Correlation with NUREG-2191 Aging Management Programs (Continued)

NUREG-2191 Section	NUREG-2191 Aging Management Program	PTN Aging Management Program
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.41)
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 EQ Requirements (Section B.2.3.42)
XI.E4	Metal-Enclosed Bus	Not Applicable (PTN U3 and U4 do not have any components within the XI.E4 AMP scope.)
XI.E5	Fuse Holders	Not Applicable (PTN U3 and U4 do not have any components within the XI.E5 AMP scope.)
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.43)
XI.E7	High-Voltage Insulators	High-Voltage Insulators (Section B.2.3.44)
N/A	PTN Site-Specific Program	Pressurizer Surge Line Fatigue (Section B.2.4.1)

Table B-4
PTN Aging Management Program Consistency with NUREG-2191

PTN Aging Management Program	Section	PTN Site-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Fatigue Monitoring	B.2.2.1	No	X.M1	Yes	No
Neutron Fluence Monitoring	B.2.2.2	No	X.M2	Yes	No
Concrete Containment Unbonded Tendon Prestress	B.2.2.3	No	X.S1	Yes	No

Table B-4
PTN Aging Management Program Consistency with NUREG-2191 (Continued)

PTN Aging Management Program	Section	PTN Site-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Environmental Qualification of Electric Equipment	B.2.2.4	No	X.E1	Yes	No
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B.2.3.1	No	XI.M1	Yes	No
Water Chemistry	B.2.3.2	No	XI.M2	No	No
Reactor Head Closure Stud Bolting	B.2.3.3	No	XI.M3	Yes	Yes
Boric Acid Corrosion	B.2.3.4	No	XI.M10	Yes	No
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	B.2.3.5	No	XI.M11B	Yes	No
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	B.2.3.6	No	XI.M12	New	No
Reactor Vessel Internals	B.2.3.7	No	XI.M16A	Yes	No
Flow-Accelerated Corrosion	B.2.3.8	No	XI.M17	Yes	No
Bolting Integrity	B.2.3.9	No	XI.M18	Yes	No
Steam Generators	B.2.3.10	No	XI.M19	Yes	Yes
Open-Cycle Cooling Water System	B.2.3.11	No	XI.M20	Yes	No
Closed Treated Water Systems	B.2.3.12	No	XI.M21A	Yes	Yes
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.3.13	No	XI.M23	Yes	No
Compressed Air Monitoring	B.2.3.14	No	XI.M24	Yes	No
Fire Protection	B.2.3.15	No	XI.M26	Yes	No

Table B-4
PTN Aging Management Program Consistency with NUREG-2191 (Continued)

PTN Aging Management Program	Section	PTN Site-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Fire Water System	B.2.3.16	No	XI.M27	Yes	No
Outdoor and Large Atmospheric Metallic Storage Tanks	B.2.3.17	No	XI.M29	Yes	No
Fuel Oil Chemistry	B.2.3.18	No	XI.M30	Yes	Yes
Reactor Vessel Material Surveillance	B.2.3.19	No	XI.M31	No	No
One-Time Inspection	B.2.3.20	No	XI.M32	New	No
Selective Leaching	B.2.3.21	No	XI.M33	New	No
ASME Code Class 1 Small-Bore Piping	B.2.3.22	No	XI.M35	Yes	No
External Surfaces Monitoring of Mechanical Components	B.2.3.23	No	XI.M36	Yes	No
Flux Thimble Tube Inspection	B.2.3.24	No	XI.M37	Yes	No
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.25	No	XI.M38	New	No
Lubricating Oil Analysis	B.2.3.26	No	XI.M39	Yes	No
Monitoring of Neutron-Absorbing Materials other than Boraflex	B.2.3.27	No	XI.M40	Yes	No
Buried and Underground Piping and Tanks	B.2.3.28	No	XI.M41	New	No
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.29	No	XI.M42	New	No
ASME Section XI, Subsection IWE	B.2.3.30	No	XI.S1	Yes	No
ASME Section XI, Subsection IWL	B.2.3.31	No	XI.S2	Yes	No

Table B-4
PTN Aging Management Program Consistency with NUREG-2191 (Continued)

PTN Aging Management Program	Section	PTN Site-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
ASME Section XI, Subsection IWF	B.2.3.32	No	XI.S3	Yes	Yes
10 CFR Part 50, Appendix J	B.2.3.33	No	XI.S4	Yes	No
Masonry Walls	B.2.3.34	No	XI.S5	Yes	No
Structures Monitoring	B.2.3.35	No	XI.S6	Yes	Yes
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.36	No	XI.S7	Yes	No
Protective Coating Monitoring and Maintenance	B.2.3.37	No	XI.S8	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.38	No	XI.E1	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	B.2.3.39	No	XI.E2	New	No
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.40	No	XI.E3A	New	No
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.41	No	XI.E3B	New	No
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.42	No	XI.E3C	New	No

Table B-4
PTN Aging Management Program Consistency with NUREG-2191 (Continued)

PTN Aging Management Program	Section	PTN Site-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.43	No	XI.E6	New	No
High-Voltage Insulators	B.2.3.44	No	XI.E7	New	No
Pressurizer Surge Line Fatigue	B.2.4.1	Yes	N/A	N/A	N/A

B.2.2 NUREG-2191 CHAPTER X AGING MANAGEMENT PROGRAMS

This section provides summaries of the NUREG-2191 Chapter X AMPs credited for managing the effects of aging at PTN.

B.2.2.1 Fatigue Monitoring

Program Description

The PTN Fatigue Monitoring AMP is an existing AMP that provides an acceptable basis for managing fatigue of components that are the subject of fatigue or cycle-based time-limited aging analyses (TLAAs) or other analyses that assess fatigue or cyclical loading.

Examples of cycle-based fatigue analyses for which this AMP is used include, but are not limited to: (a) cumulative usage factor (CUF) analyses or their equivalent that are performed in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements for specific mechanical components; (b) fatigue analysis calculations for assessing environmentally assisted fatigue (EAF); (c) implicit fatigue analyses, as defined in the American National Standards Institute (ANSI) B31.1 design code or ASME Code Section III rules for Class 2 and 3 components; (d) fatigue flaw growth analyses that are based on cyclical loading assumptions; and (e) fracture mechanics analyses that are based on cycle-based loading assumptions.

The PTN Fatigue Monitoring AMP verifies the continued acceptability of existing analyses through manual cycle counting. PTN does not use a computer software package or an on-line fatigue monitoring program to demonstrate the ability components with a calculated CUF to withstand the cyclic loads associated with plant transient operations. The program ensures that the number of occurrences and severity of each design transient remains within the limits of the component fatigue analyses, which in turn ensures that the analyses remain valid. CUF is a computed parameter used to assess the likelihood of fatigue damage in components subjected to cyclic stresses. Crack initiation is assumed to begin in a mechanical component when the CUF at a point on or in the component reaches the value of 1.0, which is the ASME Code Section III design limit on CUF values. In order not to exceed the design limit on CUF, the procedures that implement the AMP monitor the number of transient occurrences (i.e., design cycles). SLRA Section 4.3.1 provides details of the evaluation of fatigue for PTN components that have a calculated CUF. SLRA Tables 4.3-2 and 4.3-3 identify the PTN design cycles utilized in these component fatigue analyses and concludes that the projected cycles through the SPEO will not exceed the design cycles assumed in the analyses. Therefore, the current 60-year CUF values included in SLRA Table 4.3-1 remain valid for 80 years, and all CUF values remain less than 1.0 for the SPEO.

CUF_{en} is CUF adjusted to account for the effects of the reactor water environment on component fatigue life. For PTN to ensure that all potential limiting component locations are captured, all the reactor coolant pressure boundary components with existing ASME Code fatigue analyses, including those PTN site-specific NUREG/CR-6260 (Reference B.3.14) locations, have been evaluated for EAF. SLRA Section 4.3.3 provides details of the evaluation for environmentally assisted fatigue for the PTN SPEO. SLRA Table 4.3.3-1 identifies the specific PTN components, including the site-specific NUREG/CR-6260 locations, considered in the scope of the EAF evaluation. The resultant CUF_{en} Screening values for all in-scope components are included in Table 4.3.3-2. As indicated in Table 4.3.3-2, the resultant CUF_{en} Screening value for eleven (11) components exceeded 1.0 and required additional analysis. As discussed in SLRA Section 4.3.3, ten (10) of these component locations utilized 80-year projected cycles instead of the design cycles to achieve a CUF_{en} value less than 1.0. A finite element fatigue calculation was performed for the remaining component to achieve a CUF_{en} value less than 1.0. Therefore, all resultant CUF_{en} values are below the acceptance criteria of 1.0 with the exception of the pressurizer surge line welds. This exception is consistent with the results of the EAF evaluation performed for the PTN PEO. Consistent with the PEO, a flaw tolerance evaluation and inspection program for the pressurizer surge line welds is included in the Pressurizer Surge Line Fatigue AMP to ensure aging effects are managed during the SPEO. The PTN Fatigue Monitoring AMP implementing procedure will identify the 10 components and the specific projected cycles utilized in their CUF_{en} analyses. The PTN Fatigue Monitoring AMP also relies on the PTN SLR Water Chemistry AMP to provide monitoring of appropriate environmental parameters utilized in calculating environmental fatigue multipliers (F_{en} values).

The PTN Fatigue Monitoring AMP provides for corrective actions when any applicable transient cycle count comes within 80 percent of the design or projected cycle limit, as applicable. Plant management is notified in accordance with the program procedural requirements, and the condition is entered into the CAP. Component reevaluation, enhanced inspection, repair or replacement is required to demonstrate that the fatigue design limit will not be exceeded during the SPEO.

NUREG-2191 Consistency

The PTN Fatigue Monitoring AMP will be consistent with the 10 elements of NUREG-2191, Section X.M1, “Fatigue Monitoring.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Fatigue Monitoring AMP requires the following enhancements to be implemented for SLR, to be consistent with NUREG-2191 Section X.M1.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Update the AMP governing procedure to monitor the chemistry parameters that provide inputs to F_{en} factors used in CUF_{en} calculations. These chemistry parameters include dissolved oxygen and sulfate and are controlled and tracked in accordance with the PTN XI.M2 Water Chemistry AMP.
3. Parameters Monitored or Inspected	Update the AMP governing procedure to identify and require monitoring of the 80-year plant design cycles, or projected cycles that are utilized as inputs to component CUF_{en} calculations, as applicable.
5. Monitoring and Trending	Update the AMP governing procedure to identify the corrective action options if the values assumed for fatigue parameters are approached, transient severities exceed the design or assumed severities, transient counts exceed the design or assumed quantities, transient definitions have changed, unanticipated new fatigue loading events are discovered, or the geometries of components are modified.

Operating Experience

Industry Operating Experience

1. Recent domestic and international fatigue test data show that the light water reactor (LWR) environment can have a significant impact on the fatigue life of carbon and low-alloy steels, austenitic stainless steel, and nickel-chromium-iron (Ni-Cr-Fe) alloys. NRC Regulatory Guide (RG) 1.207 (Reference B.3.30) describes the methods that the staff considers acceptable for use in performing fatigue evaluations, considering the effects of LWR environments on carbon and low-alloy steels, austenitic stainless steels, and Ni-Cr-Fe alloys. Specifically, these methods include calculating the fatigue usage in air using ASME Code analysis procedures, and then employing the environmental correction factor (F_{en}), as described in NUREG/CR-6909 (Reference B.3.15). As discussed in SLRA Section 4.3.3, the methodology described in NUREG/CR-6909 was utilized in calculating the F_{en} for the PTN SPEO.

2. Regulatory Issue Summary 2008-30 (Reference B.3.82) discusses a particular analysis methodology that involves the use of the Green's (or influence) function to calculate the fatigue usage during plant transient operations such as startups and shutdowns. RIS 2011-14 (Reference B.3.83) discusses concerns associated with a computer software package developed to calculate fatigue usage during plant transient operations such as

startups and shutdowns. As discussed above, PTN utilizes a manual cycle counting program to ensure that the design cycles assumed in component-specific fatigue analyses are not exceeded. PTN does not utilize the component fatigue analysis methodology described in RIS 2008-30 or RIS 2011-14.

Site-Specific Operating Experience

1. In 2012, PTN implemented the extended power uprate (EPU) project on both units. The EPU project increased the thermal power output of each unit by approximately 15 percent. The EPU application letter from FPL to NRC, "Turkey Point Nuclear Generating Units 3 and 4—License Amendment Request for Extended Power Uprate" (ML103560169, Reference B.3.142) was submitted on October 21, 2010. Section 2.2.6 of the EPU application provided a description of PTN's evaluation of the impact the proposed EPU would have on design parameters that are used in developing transient analyses, and if those differences in design parameters would require revision to either design cycle counts or design transient severity. The scope of this review included a total of twenty-five (25) Class 1 PTN design transients. A total of 16 of these design transients were evaluated for EPU conditions, and the remaining 9 required reanalysis. The evaluation method reviewed the applicable 16 design transients and determined that pre-EPU transient severity remained bounding for EPU conditions. Computer modeling was utilized to determine the revised EPU transient severity profile for the 9 design transients requiring analysis. PTN Class 1 components that utilize these design transients as input to the component fatigue analyses were subsequently evaluated and it was concluded that the affected Class 1 components continue to meet ASME Code requirements.

   UFSAR Table 4.1-10, "Component Cyclic or Transient Limits" was updated in 2012 after implementation of the EPU project to reflect the new EPU limits. In addition, the PTN design cycle monitoring procedure was also revised in 2012 to reflect the EPU-related design information contained in UFSAR Table 4.1-10.

2. Section 2.2.3 of the EPU application evaluated the PTN reactor vessel internals (RVI) baffle-former bolts for loads resulting from EPU hydraulic pressure, seismic and LOCA loads, preload, and thermal conditions. The EPU temperature difference between the baffle plates and the core barrel produces the dominant loads on the baffle-former bolts and the loads that are most directly affected by the uprating. The EPU reactor coolant system (RCS) conditions do not affect deadweight or preload forces and do not significantly increase the seismic or LOCA loads on the bolts. It was determined that the EPU plant loading and unloading design cycles had an adverse impact of the fatigue limit for baffle-former bolts. As a result, the loading and unloading design cycle limit for the baffle-former bolts was lowered from 14,500 cycles to 2200 cycles. This new cycle limit for the baffle-former bolts has been reflected in UFSAR Table 4.1-8 of, "Design Thermal and Loading Cycles." In addition, the PTN design cycle monitoring procedure was revised in 2012 to reflect the new limit for the RVI baffle-former bolts loading and unloading cycles.

Examples 1 and 2 above illustrate that the PTN design control process is capable of identifying plant modifications that impact design transient inputs used in Class 1 component fatigue analyses and required changes to plant procedures credited for managing component aging effects during both the PEO and SPEO.

3. In 2015, during the annual performance review of the PTN design cycle monitoring procedure, it was noted that the temperature elements used to monitor the excessive pressurizer spray transient were not specifically listed in the procedure. This condition was entered into the PTN CAP and a procedure revision was made to clearly identify the temperature instrumentation required to quantify the transient.

   This example illustrates the ability of annual program procedural assessments and the CAP to effectively identify and implement required changes to procedures credited for managing the effects of aging.

4. In early 2016, it was identified that the plant operating procedures did not fully account for fatigue of the pressurizer surge line related to insurge/outsurge (I/O) transients as recommended by the Westinghouse Owners Group (WOG). The WOG recommendations addressed concerns of excessive fatigue transients on the pressurizer surge nozzle and lower head due to I/O fluctuations during heatup and cooldown.

   Consistent with the WOG recommendations, the applicable PTN operating procedures were modified to mitigate or eliminate I/O fluctuations; however, use of the recommended transient detection instrumentation was not included. The condition was entered into the CAP, and the subsequent evaluation determined that the surge line thermal transients are bounded by the fatigue evaluation. The previous three startups and shutdowns were reviewed to compare actual pressurizer I/O data to current fatigue evaluations, and the data showed significantly less pressurizer I/O transients with lower magnitudes than accounted for in fatigue evaluations. The evaluation determined that the magnitudes of temperature differentials on the surge line were less than those within the supporting analysis and that there were no fatigue issues or parameters exceeded. In addition, a revision to the PTN design cycle monitoring procedure was made to require tracking of the pressurizer I/O transient.

   This example demonstrates that the Fatigue Monitoring AMP utilizes the CAP effectively to identify and evaluate severity of design transients utilized in component fatigue analyses.

5. In the Fall of 2017, it was identified that the original license renewal minimum fatigue cycle limits for the steam generator (S/G) secondary side hydrostatic test were changed from 35 to 10 as part of the EPU project. It was determined that an oversight was made during the original EPU-related revision to the PTN design cycle monitoring procedure in not capturing this administrative change. This condition has been entered into the CAP and actions are in place to update the design cycle monitoring procedure in 2018. The

timeliness of the corrective action is acceptable as this particular secondary side test is infrequently performed.

This example demonstrates that the Fatigue Monitoring AMP identifies configuration inconsistencies, investigates their potential impact, and utilizes the CAP effectively to resolve discrepant conditions.

The OE relative to the Fatigue Monitoring AMP illustrates that the existing program will effectively provide an acceptable basis for analyses used to manage aging effects associated with material fatigue or cyclic loading. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where cycle limits are challenged. Assessments of the Fatigue Monitoring AMP are performed to identify and correct program elements that need improvement to maintain the quality performance of the program. Therefore, there is confidence that continued implementation of the Fatigue Monitoring AMP will effectively identify age-related degradation prior to failure or loss of intended function during the SPEO.

Enhancements to this AMP have been identified and implemented as a result of OE. One example of the AMP being enhanced by OE is the inclusion of pressurizer insurge/outsurge transients in the PTN design cycle monitoring procedure in 2016. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Fatigue Monitoring AMP, with enhancements, will provide reasonable assurance that aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.2.2 Neutron Fluence Monitoring

Program Description

The PTN Neutron Fluence Monitoring AMP, previously the fluence and uncertainty calculation portion of the PTN Reactor Vessel Integrity Program, is an existing program that ensures the continued validity of the neutron fluence analyses and neutron fluence-based TLAA and related analyses involving time-dependent neutron irradiation through monitoring and periodic updates. In so doing, this AMP also provides an acceptable basis for managing aging effects attributable to neutron fluence irradiation in accordance with requirements in 10 CFR 54.21(c)(1)(iii). This AMP monitors neutron fluence for reactor pressure vessel (RPV) and reactor vessel internals (RVI) components and is used in conjunction with the PTN Reactor Vessel Material Surveillance AMP.

Neutron fluence is considered to be a TLAA and is a time-dependent input to a number of RPV irradiation embrittlement (IE) analyses that are required by specific regulations in 10 CFR Part 50 for demonstration of RPV integrity. These analyses are the TLAAs for SLR and are the topic of the acceptance criteria and review procedures in NUREG-2192 (Reference B.3.10), Section 4.2, “Reactor Vessel Neutron Embrittlement Analyses.” The neutron IE TLAA in the scope of this AMP include:

a. Neutron fluence.

b. Pressurized thermal shock (PTS), as required by 10 CFR 50.61.

c. Upper-shelf energy (USE) and associated equivalent margins analyses (EMA), as required by Section IV.A.1 of 10 CFR Part 50, Appendix G.

d. Pressure-temperature (P-T) curves.

Guidance on acceptable methods and assumptions for determining reactor vessel neutron fluence is described in NRC RG 1.190 (Reference B.3.29), "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," which originated as Draft Regulatory Guide (DG)-1053 (Reference B.3.31). The methods developed and approved using the guidance contained in RG 1.190 are specifically intended to determine neutron fluence in the cylindrical region of the RPV surrounding the effective height of the active fuel.

This AMP evaluates the RPV surveillance capsule dosimetry data and updates the fluence projections in the cylindrical RPV locations, as needed. The Westinghouse Commercial Atomic Power (WCAP)-14040-A methodology, which complies with RG 1.190, is used for PTN fluence determinations in the cylindrical RPV region that surrounds the effective height of the active fuel, the RPV beltline. Calculational methods, benchmarking, qualification, and surveillance data are monitored to maintain the adequacy and ascribed uncertainty of RPV beltline neutron fluence calculations and thereby the associated RPV IE analyses:

a. This approved methodology uses geometrical and material input data, and equilibrium fuel cycle operational data, to determine characteristics of the neutron flux in the core.

b. Additionally, these data are used to determine the neutron transport to the vessel and into the reactor cavity.

c. Capsule surveillance data is used for qualification of the neutron fluence calculation.

d. The same WCAP-14040-A methodology was used for the fluence calculations performed in support of the PTN Unit 3 and Unit 4 extended power uprates (EPUs).

In addition, neutron fluence is a time-dependent input parameter for evaluating the loss of fracture toughness of RVI components due to neutron IE, irradiation-assisted stress corrosion cracking (IASCC), irradiation-enhanced stress relaxation and creep and void swelling (VS) or distortion. Fluence estimates at 80 years for RVI components are addressed in Sections B.2.3.7 and C.2.2.

Neutron fluence estimates are also necessary for the definition of the (extended) RPV beltline region, RPV locations above (or below) the effective height of the active fuel that are projected to exceed 1 x 10^{17} n/cm^2 (E > 1 MeV) during the SPEO, as defined in RIS 2014-11 (Reference B.3.37), "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components."

The WCAP-14040-A methodology was also used to estimate conservative neutron fluence for the RPV locations above and below the effective height of the active fuel for SLR. End-of-license (life) 80-year fluence in PTN RPV regions above the active fuel region (e.g., in nozzle locations) are currently projected to exceed the 1 x 10^{17} n/cm^2 threshold prior to the end of the SPEO, whereas RPV locations below the active fuel region do not, as described in Section 4.2.1. FPL follows related industry efforts, such as those from the Pressurized Water Reactor Owners Group (PWROG), and will use the information from those efforts to provide additional justification for fluence determinations in those areas prior to entering the SPEO.

Neutron fluence calculations are updated periodically, such as in support of related licensing actions and surveillance capsule information, to ensure that the plant and core operating conditions remain consistent with the assumptions used in the neutron fluence analyses and that the related analyses are updated as necessary. Per the NRC approval letter (Reference B.3.138), the PTN capsule withdrawal schedule has been adjusted to provide for capsule withdrawal equivalent to 80-year exposure for information to support operation beyond 60 years, as described in Section B.2.3.19.

There are no specific acceptance criteria values for neutron fluence; the acceptance criteria relate to the different parameters that are evaluated using neutron fluence. NRC RG 1.190 provides guidance for acceptable methods to determine neutron fluence for the RPV (effective height of the active fuel) beltline region. Applying NRC RG 1.190-adherent methods to determine neutron fluence in locations other than those close to the active fuel region of the core warrants additional justification.

Prior to entering the SPEO, PTN will follow the related industry efforts, such as by the PWROG, and will use the information or other information to provide additional justification for use of the WCAP-14040-A or similar methodology for the estimate of RPV nozzle location fluence. This further justification will draw from Sections 1 and 2 of UFSAR Appendix 4A, and will include discussion of the neutron source, synthesis of the flux field and the order of angular quadrature (e.g., S8), etc. used in the estimates for projection of TLAA to 80 years.

NUREG-2191 Consistency

The PTN Neutron Fluence Monitoring AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section X.M2, "Neutron Fluence Monitoring."

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	PTN will follow the related industry efforts, such as by the PWROG, and use the information from supplemental nozzle region dosimetry measurements and reference cases or other information to provide additional justification for use of the WCAP-14040-A or similar methodology for the estimate of RPV fluence in regions above or below the active fuel region.
6. Acceptance Criteria	Draw from Sections 1 and 2 of UFSAR Appendix 4A and include discussion of the neutron source, synthesis of the flux field and the order of angular quadrature (e.g., S8), etc. used in the estimates for projection of TLAAs to 80 years in the additional justification of RPV fluence in regions other than active fuel region.

Operating Experience

Industry Operating Experience

Recent industry licensing actions that affect plant life and/or power level, include consideration of fluence in adjacent RPV regions outside the effective height of the active fuel to confirm that RPV limiting components, relative to embrittlement and pressure-temperature limits, are those that surround the effective height of the active fuel; through demonstrating that:

a. RPV nozzle fluence determinations are conservative (ML15096A324) or

b. Nozzle regions will experience a fluence less than $1x10^{17}$ n/cm^2 at the end of license/life (ML16081A333).

RPV nozzle belt fluence was also addressed for original license renewal. PTN licensing actions that impact CLB information consider the following:

- Recent utility licensing submittals.
- Recent NRC safety evaluations (SEs).
- Recent NRC requests for additional information (RAIs).
- Recent utility responses.

Site-Specific Operating Experience

The RPV beltline neutron fluence and uncertainty calculations for PTN Units 3 and 4 have been performed in accordance with the guidelines of the RG 1.190 (Reference B.3.29) and validated using data obtained from capsule dosimetry. The results of the fluence uncertainty values to date are within the NRC-suggested limit of ±20 percent. RPV beltline fluence determinations support the RPV IE analyses documented in the CLB, including update and confirmation to EPU and P-T limit curve updates.

This methodology represents a continuous validation process to ensure that no biases have been introduced for limiting RPV beltline locations, and that the uncertainties in those locations remain comparable to the reference benchmarks upon which RPV embrittlement analyses, that demonstrate continued RPV integrity, are based.

To date, no enhancements to the AMP have been identified as a result of operating experience. Operating experience is reviewed such that if additional or different considerations in neutron fluence determination are required, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Neutron Fluence Monitoring AMP, with enhancements, will provide reasonable assurance that applicable RPV neutron irradiation embrittlement analyses (i.e. TLAAs), that demonstrate RPV integrity, and radiation-induced aging effect assessments for RVI components will remain within their applicable limits reported in the CLB during the SPEO. The PTN Neutron Fluence Monitoring AMP, in conjunction with the PTN Reactor Vessel Material Surveillance AMP, will also provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of these AMPs will be maintained consistent with the CLB during the SPEO.

B.2.2.3 Concrete Containment Unbonded Tendon Prestress

Program Description

The PTN Concrete Containment Unbonded Tendon Prestress AMP is an existing condition monitoring AMP. The PTN Concrete Containment Unbonded Tendon Prestress AMP is based on the ASME Code Section XI, Subsection IWL requirements in the 2001 Edition, with 2003 Addenda (Reference B.3.132). The PTN Concrete Containment Unbonded Tendon Prestress AMP includes confirmatory actions that monitor and evaluate loss of containment tendon prestressing forces during the current term and will continue through the SPEO.

Loss of containment tendon prestressing forces is a TLAA evaluated in accordance with 10 CFR 54.21(c)(1)(iii). The PTN Concrete Containment Unbonded Tendon Prestress AMP, as part of the PTN ASME Section XI, Subsection IWL AMP, manages loss of containment tendon prestressing forces in the current period of extended operation (PEO). This TLAA AMP consists of the assessment of measured tendon prestressing forces from examinations performed through the PTN ASME Section XI, Subsection IWL AMP. The adequacy of the prestressing force for each tendon group based on type (i.e., hoop, vertical, and dome) and other considerations (e.g., geometric dimensions, whether affected by repair/replacement, etc.) establishes (a) acceptance criteria in accordance with Subsection IWL and (b) trend lines constructed based on the guidance provided in NRC IN 99-10 (Reference B.3.44), "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The calculation of prestressing losses, predicted upper limits and predicted lower limits for each tendon group is in accordance with the guidelines of the NRC RG 1.35.1 (Reference B.3.18), "Determining Prestressing Forces or Inspection of Prestressed Concrete Containments."

This AMP periodically evaluates tendon forces measured by the PTN ASME Section XI, Subsection IWL AMP (Section B.2.3.31), such that corrective action can be taken, if required, prior to tendon forces falling below minimum required values (MRV) established in the design. This AMP addresses the TLAA assessment of unbonded tendon prestressing forces measured at control and randomly selected tendon samples (dome, hoop, and vertical) at PTN Unit 3 and Unit 4. The prestressing forces of the concrete containment tendons are measured for sample tendons using the lift-off method, or equivalent method.

The loss of concrete containment tendon prestressing forces is detected by comparing the measured data against the predicted force values from the respective containment tendon loss of prestress TLAA. In addition, loss of prestressing forces are also detected by comparing the tendon force trend lines, constructed from surveillance measurements, against predicted force values. In addition to PTN Unit 3 and Unit 4 ASME Section XI, Subsection IWL examination requirements, all measured prestressing forces, up to the current examination, are plotted against time. The predicted lower limit (PLL), MRV, and trend-line curves are developed for each tendon group examined for the SPEO. The trend line represents the general variation of prestressing forces with time based on the actual measured forces in individual tendons of the specific tendon group. The trend line for each tendon group is constructed by regression analysis of measured prestressing forces in individual tendons of that group obtained from previous examinations. The inspections are conducted every five years (i.e., 1, 3, 5, 10, 15, 20, 25, 30, 35, 40, 45th year, etc.) on alternating units. The PLL line, MRV, and trend line for each tendon group have been projected to the end of the SPEO as described in Section 4.5. The trend lines will be updated after each scheduled examination using methods consistent with RG 1.35.1.

The prestressing force trend line for each tendon group shall not cross the appropriate MRV curve prior to the next scheduled examination. In addition, the constructed trend line shall not cross the appropriate PLL curve for any of the tendon groups. In case any of the two precedent criteria fail, the cause shall be determined, evaluated and corrected in a timely manner. If acceptance criteria are not met, then either systematic re-tensioning of tendons or a reanalysis of the concrete containment is warranted so that the design adequacy of the containment is demonstrated.

NUREG-2191 Consistency

The PTN Concrete Containment Unbonded Tendon Prestress AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section X.S1, “Concrete Containment Unbonded Tendon Prestress.”

Exceptions to NUREG-2191

None.

Enhancements

The following enhancement will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
1. Scope	Update the pertinent implementing documents for each 10-year interval within the SPEO and update the trend lines consistent with RG 1.35.1 following each inspection.

Operating Experience

<u>Industry Operating Experience</u>

External (industry) operating experience is evaluated through the action request (AR), initial screening for the CR, process to confirm applicability to PTN or identify the appropriate adjustments / improvements to the AMP. There has been no industry operating experience since entering the PEO, in July of 2012, that address tendon prestress calculation apart from the ASME XI. Subsection IWL considerations.

<u>Site-Specific Operating Experience</u>

Due to the close interface between the PTN Concrete Containment Unbonded Tendon Prestress AMP and the PTN ASME Section XI, Subsection IWL AMP (Section B.2.3.31), overlap of site-specific operating experience is typical.

Physical tendon surveillances, comprising visual inspection plus force monitoring and inspection, as well as tensile testing, have been conducted at ten-year intervals for each unit. The inspections are conducted on alternating five-year intervals ensuring each inspection is completed every ten years for each unit. Tendon surveillances conducted since receipt of the original license extension include:

- 2017 (45Th interval - Unit 3 visual, Unit 4 physical).
- 2012 (40th interval - Unit 3 physical, Unit 4 visual).
- 2007 (35th interval - Unit 3 visual, Unit 4 physical).
- 2002 (30th interval - Unit 3 physical, Unit 4 visual).

The evaluation of inspection results for these intervals found that the containment structure had experienced no abnormal degradation of the post-tensioning system and all nonconformance items had been identified, documented, and reported as required. For example:

- During the 40th year tendon surveillance in 2012, the average of all measured tendon forces was above minimum required prestress, all of the tendon liftoffs were found within acceptable limits with each tendon found to have a liftoff force greater than 95 percent of the tendon predicted force. Regression output data for the dome, hoop and vertical tendons for each unit forecast to be greater than the lower bound values. As indicated in the above description, the end of PEO force calculations are a TLAA that have been projected to 80 years and the trend lines will be updated after each interval.

- During the PTN Unit 3 40th year physical tendon surveillance also in 2012, three tendons were unable to be stressed to overstress force (80 percent of the Guaranteed Ultimate Tensile Strength (GUTS)) due to the thread capacity between the test machine pullrod and the tendon anchorhead. Based on the condition found during the inspection, a CR was written, evaluated as described below and completed prior to startup from the RFO.

  The engineering evaluation of the thread capacity of a vertical tendon, a dome tendon, and a horizontal tendon was based on field measurements of the anchorhead and available stub rods used to couple the anchorhead to the pullrod. The thread capacity maximum failure load was determined to be inadequate to stress the subject tendons to their overstress force and concluded that, "There are no modifications to the stressing equipment and/or anchorhead that would result in a capacity equal to or greater than the new overstress force." Justification was provided for the subject tendons to be stressed to

70 percent of GUTS instead of 80 percent, including linear extrapolation from the 70 percent scenario to allow for the best approximation of the 80 percent scenario. The extrapolated value was then compared to the acceptance criteria defined in IWL-3221.1(d). IWL-3221.1(d) acceptance criteria indicates that measured tendon elongation variance from the last measurement, adjusted for effective wires or strands, be less than 10 percent. This justification was accepted by FPL Engineering, prior to startup from the RFO, as follows:

- o The maximum force of the tendon is solely due to the dimensional limitations of the anchor head, and not the condition of the wires or coupling components. That is, if greater thread engagement were possible-either by way of a deeper anchor head or a larger thread diameter-the tendon would be reasonably expected to achieve the New Overstress Force.

- o The behavior of the tendon wires can be shown to be elastic during the stressing of the tendon up to the Overstress Force. On a straight-line curve, any point along the curve can be determined based on the equation of the line. Therefore, a calculation of the extrapolated value of the New Overstress Force, beyond the recommended 70 percent of GUTS, can be calculated with a high degree of confidence. Similarly, a linear interpolation can be performed, using the original Overstress Force, in order to find 70 percent of GUTS at installation, thus making a reasonable comparison to the recommended maximum force possible.

- o The requirement of IWL item 3221.1(d) does not include the specific requirement to stress the tendon to Overstress. Rather, the decision to stress the tendon to its Overstress Force has been chosen by FPL in order to more easily compare the previous measurement to the current measurement. Therefore, the methodology used to perform the comparison of the measured tendon elongation to the last measured elongation is based on reasonable engineering judgment.

The adjustment to GUTS percentage were implemented for these tendons and the thread capacity maximum failure load shown to be adequate.

- During the 30th year physical tendon surveillance in 2002, a missing button head was found on each end of a hoop tendon, due to a broken or missing wire that did not impact the tendon/anchorage. An NCR was written and a calculation generated to update the tendon stress analysis of the Unit 3 containment building. From the calculation, a trend line was used to calculate the amount of prestress loss from the 25th year to the 60th year. Based on the 90 effective wires in the 25th year, recorded lift-off force, and the prestress loss calculated from the 25th to the 60th year, the hoop tendon with 88 wires in the 60th year was projected to have a force greater than the minimum required force. Based on this evaluation, the containment structure was determined to be acceptable. As indicated in the above description, the end of PEO force calculations are a TLAA that have been projected to 80 years and the trend lines will be updated after each interval.

- In 2007, a quality assurance evaluation was performed on the performance of the 35th year tendon surveillance. The evaluation concluded that the specified inspections and tests were satisfactorily performed.

- Lastly, internal observations were conducted on the performance of the lift-off force test for one of the containment tendons in 2001. All items observed were determined to be satisfactory. In addition, a surveillance was conducted on the performance of the Unit 3 containment structural integrity inspection. It was concluded that inspection activities are being satisfactorily performed per procedures, as-found tendon lift-off values have been within predicted values, and visual inspections have not revealed any significant degradation to the containment structure.

These examples of site-specific operating experience during the original PEO, including past corrective actions, provide reasonable assurance that the PTN Concrete Containment Unbonded Tendon Prestress AMP activities effectively manage loss of prestress forces. Site-specific operating experience shows that conditions are identified and evaluated in a timely manner through the PTN ASME Section XI, Subsection IWL AMP. To date, no enhancements to the PTN Concrete Containment Unbonded Tendon Prestress AMP have been identified as a result of operating experience. However, operating experience is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Concrete Containment Unbonded Tendon Prestress AMP, with enhancement, in conjunction with the PTN ASME Section XI, Subsection IWL AMP, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMPs will be maintained consistent with the CLB during the SPEO.

B.2.2.4 Environmental Qualification of Electric Equipment

Program Description

The PTN Environmental Qualification of Electric Equipment AMP is an existing AMP, previously the Environmental Qualification (EQ) Program, that manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. The NRC has established nuclear station EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.”

This AMP provides the requirements for the EQ of electrical equipment important to safety that could be exposed to harsh environment accident conditions as required by 10 CFR 50.49 and RG 1.89 (Reference B.3.22), "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants." This AMP is established per the requirements of 10 CFR 50.49 to demonstrate that certain electrical components located in harsh plant environments (i.e., those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high-energy line breaks (HELBs), or a main steam line break (MSLB) inside or outside the containment, from elevated temperatures or high radiation or steam, or their combination) are qualified to perform their safety function in those harsh environments after the effects of inservice (operational) aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ, and that the equipment be demonstrated to function in the harsh environment, following aging.

The preventive actions associated with this AMP include the identification of qualified life and specific maintenance/installation requirements to maintain the component within the qualification basis. This AMP provides EQ-related surveillance and maintenance requirements for EQ equipment, and monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life. Although 10 CFR 50.49 does not require monitoring and trending of EQ equipment, this AMP does provide surveillance and maintenance requirements for the EQ equipment, verifies that the required activities are performed, and tracks and maintains the service life of qualified components. Implementation of this AMP is a coordinated effort from a variety of departments within the PTN and fleet organization to ensure the continued environmental integrity of specified equipment to remain operable when exposed to a harsh environment. Surveillance and maintenance is performed on all equipment on the EQ list to ensure the equipment remains qualified. The PTN EQ of Electric Equipment AMP will also provide for visual inspection of accessible, passive EQ equipment at least once every 10 years (see Enhancement statement, below). This inspection is performed to view the EQ equipment, and also to identify any adverse localized plant environments.

If monitoring is used to modify a component's qualified life, then appropriate site-specific acceptance criteria will be established based on applicable 10 CFR 50.49(f) qualification methods. Visual inspection results will show that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate age degradation. An unacceptable indication is defined as a noted condition or situation, that if left unmanaged, could potentially lead to a loss of intended function.

When analysis cannot justify a qualified life in excess of the original period of extended operation (PEO) and up to the end of the SPEO, then the component parts will be replaced, refurbished, or requalified prior to exceeding the qualified life as required by 10 CFR 50.49. Re-analysis of an aging evaluation addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. The PTN Environmental Qualification Documentation Packages (EQ Doc Pacs) require a TLAA performed under 10 CFR 54.21(c)(1).

NUREG-2191 Consistency

The PTN EQ of Electric Equipment AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section X.E1, “Environmental Qualification of Electric Equipment.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN EQ of Electric Equipment AMP will be enhanced per the following table for alignment with NUREG-2191 and to capture SLR commitments. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Visual inspection of accessible, passive EQ equipment will be performed at least once every 10 years with the first periodic visual inspection being performed prior to the SPEO.

Operating Experience

<u>Industry Operating Experience</u>

Industry operating experience on Environmental Qualification covers a long period of time, dating back to the 1970s. Every nuclear plant has an EQ program, and the NUGEQ (Nuclear Utility Group on Equipment Qualification) was founded in 1981 to bring the licensees together in order to share lessons learned on EQ, to provide input on EQ technical and licensing issues, and to create a forum for learning, as the NRC began to expand on EQ rulemaking after the TMI-2 event. With respect to the fleet, there is an EQ program owner and an assigned EQ support engineer at the various sites, including PTN. These individuals receive and address (if necessary) the industry OE on EQ (from other plants, from NRC, and from external industry guidance) and also address industry technical issues regarding EQ components (e.g., 10 CFR Part 21 Notifications on EQ equipment, and other component vendor reports / circulars / bulletins).

In recent years, licensees (those that have completed the License Renewal process from 40-to-60 years) have been focused on updating their EQ programs to reflect the new plant lifetime of 60 years. PTN completed this effort shortly after receiving its renewed license, around 2002/2003. Other industry issues have involved component upgrades (replacement of older model equipment with newer models, such as Rosemount 3154N transmitters replacing older 1153 and 1154 models). While these items are not typically thought of as industry OE, they are discussed among the licensees and are topics of discussion at industry meetings (such as the annual NUGEQ meeting). In the NUGEQ meeting held in Nov. 2017, one topic discussed was the EQ DBA (Design Basis Assurance) Inspections being conducted by the NRC. The licensees covered the topics brought out during individual plant EQ DBA inspections (in 2017), and learned what issues/problems were identified. A fleet representative attended this meeting. The EQ of Electric Equipment program at PTN is informed by these meetings, and also by addressing generic industry EQ issues from the NRC or other organizations. The incorporation of industry OE into the PTN EQ of Electric Equipment program is highlighted in PTN EQ procedure 0-ADM-703 (in Sect. 3.5).

<u>Site-Specific Operating Experience</u>

The following examples of OE provide objective evidence that the EQ of Electric Components program will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

<u>System Health Reports</u>

A review of quarterly system health reports (covering the period from 1Q 2012 through 4Q 2017) was conducted to determine the EQ of Electric Equipment program performance during the PEO. The review indicated that the program has been functioning well during the entire period, with no drops in ranking or evaluation. No EQ equipment failures were identified. The primary focus was on administrative changes in the EQ program, as follows - a) the program structure was changed in 2014/2015, with the move to having a fleet program owner and support engineering staff at the various fleet sites, and b) the implementation (in 2016/2017) of equipment replacement plans (e.g., for Unit 4 sump level transmitters) whereby the replacements were spread out over multiple plant outages, reducing the maintenance burden (covered under AR2097896). The EQ program allowed for the reduction of risk (with fewer components being changed out at once), and this extended replacement plan will also be utilized for transmitter replacements on Unit 3 (covered under AR2226823). Other items mentioned in the system health reports over this period included updates of individual EQ Document Packages to address component upgrades (to newer models, such as the Rosemount 3154N transmitters previously mentioned). No other issues were identified from the system health report review for the PTN EQ Electric Equipment AMP. Other examples of site-specific operating experience (corrective action items, self-assessment items, action requests, etc.,) are presented below.

1. Corrective Action Item, MOV-4-350 Cable Discrepancy

   In 2008, the regular maintenance inspection for MOV-4-350 (grease and inspect) was being performed when it was identified that the Raychem seals/splice on the 480 VAC cables into the motor termination box were starting to crack (showing signs of deterioration) and that copper was showing at the lug (on the "A" phase). The subsequent evaluation showed that the cracks in the Raychem seals are minor, that water intrusion is not a concern for the location of this component, and that all three phases of the 480 VAC cable were successfully meggered. A work order was written to repair the cables and the splice. This item highlights that EQ program awareness is present when EQ components are receiving regular maintenance / inspections, and that the program provided input into the corrective action process (the evaluation of the CR), to resolve the concern.

2. QRNO 04-042, Environmental Qualification (EQ) Program Review/Maintenance/Work Control

   An EQ Maintenance/Work Control functional area audit was conducted in 2004 to verify that EQ activities are scheduled to ensure that the qualified life of EQ components requiring maintenance is not exceeded and that the maintenance performed will maintain the qualification of the component.

   The audit concluded that the scheduling and maintenance performed on EQ components indicates that components required to perform under significant environmental stresses will be capable of accomplishing their safety-related EQ functions. However, a process deficiency was identified with respect to when the next required EQ maintenance interval would be defined (i.e., when the new interval would start). The consequence is that it is possible to replace an EQ component when substantial qualified life is still remaining. Condition Report (CR) CR04-2393 was initiated to address this issue. Issues related to QA records were also identified. CR 04-2397 was written to address QA records that cannot be easily found or easily retrievable. The audit report was closed without noting (prior to) when the CRs were closed. The audit also identified administrative enhancements to the EQ Maintenance Index.

   This example provides objective evidence that the program is enhanced when necessary through periodic self-assessments. Periodic self-assessments facilitate continuous improvement demonstrating that the EQ program will adequately manage electrical components subject to the requirements of environmental qualification through the SPEO.

3. PTN 11-010, Nuclear Oversight Department Audit of the Engineering Programs Functional Area

   An Engineering Programs functional area audit was conducted in 2011. With respect to the EQ Program, the audit concluded that the program is overall satisfactory - the program is meeting procedural guidelines for implementation, and the required EQ surveillance and documentation is being performed. Minor issues with procedure updates were identified. A CAP document was initiated to ensure procedure change request (PCR) adherence when correcting procedural information. The Engineering Programs audit also found that completion of EQ impact evaluations for one failed component were not properly identified. A CAP document was initiated to specifically evaluate the failures for an EQ failure or other EQ impact as required. Nuclear Oversight issued an AR to document and correct the issue; the functional area audit report was issued before final resolution of this item.

This example provides objective evidence that periodic audits of the EQ program are performed to identify the areas that need improvement to maintain the performance and quality of the program. The CAP will identify inadequacies and root causes, and corrective actions will be implemented to prevent recurrence, thus demonstrating that the EQ program will adequately manage electrical components subject to the requirements of environmental qualification through the SPEO.

4. Action Request Record, Tracking of License Renewal Commitments for PTN (2011/2012)

   This AR addressed the tracking of LR commitments for PTN. One small portion of this Action Request involved the PTN EQ program, with respect to verification and validation that the program is being effectively implemented. The AR Completion Notes indicated that the program is being successfully implemented in accordance with the program description in the PTN LR SER, NUREG-1759. The AR was closed in early 2012.

5. Corrective Action Program Document 2004

   The evaluation determined that in October / November 2004, an adverse localized environment caused by heat was found in the Unit 3 containment (problem was discovered during a refueling outage, when abnormal pressurizer pressure indications were noted in the control room, for a pressurizer instrument loop). Conduits located at the ceiling above the Reactor Hot Leg Piping were discovered to contain heat degraded instrument cable. Similar areas were discovered in Unit 4 in April 2005. The conditions and corrective actions were documented on CRs (see below). The cable was replaced with an ITT surprenant silicone rubber cable qualified by new EQ Doc Pac 15.1. This initial CR (Oct. 2004) led to the issuance of 3 child records (new CRs), as the extent-of-condition of the damaged cable issue was explored, via walkdowns and CHAR testing conducted on other cables. Walkdowns (later in 2004 and in early 2005) showed that several RCS cables were damaged and located in conduit in narrow areas above uninsulated pipe stubs, and also discovered that a ventilation register was mistakenly closed. All damaged cables were replaced, the ventilation louvers were opened and tagged for future confirmation (as part of the containment close-out procedure) and additional walkdowns of RCS loops and other hot piping in containment were performed (early 2005). Pipe insulation deficiencies were identified and corrected. Unit 4 was checked as well (in 2005), following the Unit 3 inspections, tests, and corrections. The configuration of the cable conduits for Unit 4 was not identical to the problems found in

Unit 4, and only a few degraded cables were found - these were replaced (4B and 4C hot leg cables). The problem was resolved and any piping insulation deficiencies were also corrected (for both units), as part of this effort.

The initiation of corrective action, along with identification of program deficiencies and subsequent corrective actions prior to loss of intended function, demonstrate that the PTN EQ of Electric Equipment AMP, with the correction of the identified deficiencies, will continue to be effective. The continued application of these proven methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the CLB through the SPEO. To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Environmental Qualification of Electric Equipment AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended functions of EQ components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3 NUREG-2191 CHAPTER XI AGING MANAGEMENT PROGRAMS

This section provides summaries of the NUREG-2191 Chapter XI AMPs credited for managing the effects of aging at PTN.

B.2.3.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The existing PTN ASME Section XI Inservice Inspection, Subsections ASME Section XI, IWB, IWC, and IWD AMP inspections identify and correct degradation in ASME Code Class 1, 2, and 3 components and piping. In accordance with 10 CFR 50.55a, ISI program plans documenting the examination and testing of Class 1, 2 and 3 components are prepared in accordance with the rules and requirements of ASME Code Section XI, 2007 Edition and Addenda through 2008 (Reference B.3.122). This AMP describes the long-term inspection program for Class 1, 2 and 3 components.

The AMP manages the aging effects of loss of material, cracking, and loss of mechanical closure integrity, and provides inspection and examination of accessible components, including welds, pump casings, valve bodies, and pressure-retaining bolting. This condition monitoring program includes periodic visual, surface, and volumetric examination and leakage testing of Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments; pressure-retaining bolting for assessment, identification of signs of age-related degradation; and establishment of corrective actions. The program includes examinations and tests performed to identify and manage cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components. Inspection of these components is in accordance with Subsections IWB, IWC, and IWD, respectively.

The PTN ASME Section XI, Subsections IWB, IWC, and IWD, ISI AMP inspections identify and correct degradation in Class 1, 2, and 3 components and piping. Inspection methods and frequency are determined in accordance with the requirements of Tables IWB-2500-1 (Class 1), IWC-2500-1 (Class 2), and IWD-2500-1 (Class 3). Examinations are scheduled in accordance with Inspection Program B, as described by Sub-article IWB-2412 and Table IWB-2412-1 as well as the 5th Interval-ISI-PTN-3/4-Program Plan (ISI Program Plan) (Reference B.3.132).

The ISI of Class 1, 2, and 3 components and integral attachments (i.e., the scope of this AMP) has been in place since initial operation of the plant, and the inspections are conducted as part of the PTN ISI Program, currently based on the PTN ISI Program Plan. Examinations are performed as specified to identify the overall condition of components and to ensure that any degraded conditions identified are corrected prior to returning the component to service. The PTN ISI Program Plan is updated at the end of the 120-month interval to the latest approved edition of the ASME Code Section XI, identified by 10 CFR 50.55a, twelve months prior to the end of the 120-month interval. All examinations and inspections performed in accordance with the program plan are documented by records and reports, which are submitted to the NRC as required by IWA-6000. Implementation of this AMP is the responsibility of the Component

Supports and Inspections (CSI) manager, and is controlled in accordance with approved procedures.

Inspection results are evaluated by qualified individuals in accordance with ASME Code Section XI acceptance criteria. Components with indications that do not exceed the acceptance criteria are considered acceptable for continued service. Indications that exceed the acceptance criteria are documented and evaluated in accordance with the PTN CAP. Components will be accepted based on engineering evaluation, repair, replacement or analytical evaluation. Repairs or replacements are performed in accordance with ASME Code Section XI, Subsection IWA-4000 and IWA-6000.

Enhancements to the program are required to ensure consistency with NUREG-2191 and in order to manage the aging effect of loss of material due to wear in the control rod drive mechanism (CRDM) head penetrations. These enhancements include developing a wear-depth measurement process, incorporating the process into existing inspections, and developing a procedure to estimate the wall thickness of the accessible CRDM housing penetration wear in the area of interest and compare the results to the design basis analyses.

NUREG-2191 Consistency

The PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

Exceptions to NUREG-2191

None.

Enhancements

The PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP will be enhanced as follows for alignment with NUREG-2191. Enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Develop a wear-depth measurement process for the CRDM head penetrations. Incorporate inspections using the demonstrated process at accessible locations to measure depth of wear on the control rod drive mechanism (CRDM) housing penetration wall associated with contact. Develop a procedure to estimate the wall thickness of the accessible CRDM housing penetration wear in the area of interest at the end of the next reactor vessel head inspection interval and compare that projected wall thickness to the thickness used in the design basis analyses to demonstrate validity of the analyses.
10. Operating Experience	Evaluate industry experience related to CRDM housing penetration wear due to thermal sleeve centering pads and initiatives to measure CRDM housing penetration wear and resulting nozzle wall thickness

Operating Experience

Industry Operating Experience

As described below, industry operating experience indicates that certain primary system components are susceptible to cracking and can cause borated water leakage. PTN evaluates industry OE items for applicability per the FPL Fleet OE Program and takes corrective actions, when necessary.

1. PTN evaluated NRC IN 2004-11 "Cracking in Pressurizer Safety and Relief Nozzles and in Surge Line Nozzle" and determined that the issue is not applicable to PTN. NRC IN 2004-11 states that indications were found in Alloy 82/182 weld metal on pressurizer nozzles, but the indications did not extend into the base metal. A metallurgical analysis concluded that primary water stress corrosion cracking occurred in the Alloy 82/182 nozzle weld material. The pressurizer spray nozzles at PTN are constructed of SA-182, which is not the same as Alloy 82/182, and not susceptible to primary water stress corrosion cracking. Therefore, IN 2004 11 is not applicable to PTN and no corrective actions were required.

2. PTN evaluated NRC IN 2005-02 "Pressure Boundary Leakage Identified on Steam Generator Bowl Drain Welds" and determined that the issue is not applicable to PTN due to there being no pressure boundary drain nozzles in the steam generator bowls. This evaluation is also applicable to the PTN replacement steam generators.

3. PTN evaluated NRC IN 2006-27 "Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors" and determined that

inspections needed to be performed on the pressurizer heater sleeve welds during Unit 3 RFO 23 (Fall 2007) and Unit 4 RFO 23 (Fall 2006). The inspections were performed and results indicated no evidence of leakage or degradation of the pressurizer heater sleeve welds on either unit. No further actions were required.

The examples above demonstrate that the PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP reviews OE and incorporates applicable industry OE into the program. This ensures that the AMP will continue to be effective during the SPEO as it is informed and enhanced by industry OE.

Site-Specific Operating Experience

The following review of site-specific OE, including corrective actions, audits, NRC inspections, and program health reports provides examples of how PTN is managing aging effects associated with the ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP.

1. During Unit 3 RFOs 26 (Fall 2012) and 28 (Fall 2015), remote bare metal visual examinations of bottom-mounted instrumentation (BMI) nozzle penetrations from the outside surface of the reactor vessel lower head were performed. The examinations revealed relevant indications of staining and discoloration in the examination region of the BMI nozzles. None of the indications were related to active leakage from the BMI nozzle penetrations. Results of the Unit 3 RFO 28 exams were compared to data obtained during the Unit 3 RFO 26 exams after CO_2 cleaning, with no changes noted. The discolorations are embedded in the metal and could not be removed during CO_2 cleaning. The staining and discoloration did not interfere with the examination requirements as required by Code Case N 722 1. The engineering evaluation noted that the stain/discolored streaks extend up from the side of the vessel which indicates that they are most likely the result of historical cavity seal ring leakage. This is supported by the fact that cavity seal ring leakage has occurred in the past during refueling when the cavity was flooded with borated water. There is no evidence of corrosion damage to the vessel or other components affected by the leakage. This was validated by the BMI inspector, who stated that visual data collected during RFO 28 was compared to the data collected during RFO 26 with no changes noted. This indicates the condition was not degrading. The inspection concluded that no further evaluation was required. The corrective actions for this item were to clean and re-inspect the reactor vessel lower head surface including the BMI nozzles and surrounding area after initial inspection in Unit 3 RFO 30 (Fall 2018). This allows for further trending of the degradation that will in turn determine if any additional corrective actions will be required.

2. QA Audits

   2010 ISI/Engineering Functional Area Audit: This audit reviewed the corrective actions from the 2008 Component Support and Inspection (CSI) Audit and a 2009 CSI Quick Hit Self-Assessment (QHSA). The audit concluded that repair/replacement activities were performed and documented in accordance with program requirements.

2011 Engineering Programs/Engineering Functional Area Audit: This audit included an assessment of elements of the inservice testing and non-destructive examination (NDE) programs. All elements assessed were determined to be satisfactory and no issues were identified.

3. NRC Inspections

NRC Integrated Inspection Reports for 4Q 2010, 2Q 2011, 1Q 2012, 2Q 2012, 3Q 2012, 4Q 2012, 1Q 2013, 2Q 2013, 3Q 2013, 4Q 2013, 1Q 2014, 2Q 2014, 3Q 2014, 4Q 2014, 1Q 2015, 2Q 2015, 3Q 2015, 4Q 2015, 1Q 2016, 2Q 2016, 3Q 2016, 4Q 2016, 1Q 2017 and 2Q 2017, Accession Nos. ML110280004, ML112082835, ML11117A299, ML12213A232, ML12304A087, ML13030A208, ML13115A425, ML13211A151, ML13304A619, ML1403A306, ML14121A165, ML14212A253, ML14296A129, ML15030A278, ML15121A674, ML15212A695, ML15309A090, ML16095A172, ML16124A272, ML16225A526. ML16315A226, ML17025A006, ML17131A318 and ML17223A012, respectively (References B.3.54, B.3.55, B.3.56, B.3.57, B.3.58, B.3.59, B.3.63, B.3.64, B.3.65, B.3.66, B.3.67, B.3.68, B.3.69, B.3.70, B.3.71, B.3.72, B.3.73, B.3.74, B.3.75, B.3.76, B.3.78, B.3.79, B.3.80, and B.3.81) were reviewed.

During the inspections documented in the above-listed inspection reports, the inspectors reviewed selected surveillance tests, including inservice testing, to verify the tests met the TS requirements, the UFSAR, and the procedural requirements, and to verify that the test demonstrated that the applicable systems were operationally ready to perform their intended functions. In addition, the inspectors evaluated the effect of the testing activities on the plant to ensure that conditions were adequately addressed by the licensee staff, and that after completion of the testing activities, equipment was returned to the status required for the system to perform its safety function.

During the 4Q 2010, 2Q 2011, 1Q 2012, 4Q 2012, 2Q 2014, 4Q 2014, 4Q 2015, 2Q 2016 and 2Q 2017 inspections, the inspectors reviewed the implementation of the ISI program for monitoring degradation of the RCS boundary and risk significant piping boundaries. The inspectors conducted on-site review of NDE and welding activities and records to evaluate compliance with the applicable edition of ASME Code Section XI and Section V requirements, and to verify that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement. In addition, when required by 10 CFR 50.55a, the inspectors observed portions of the vessel upper head penetration (VUHP) bare metal visual examinations and reviewed NDE reports for selected VUHPs to determine if the activities, including the disposition of indications and defects, were conducted in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D). The 4Q 2010 inspection identified one finding. Further details are provided below.

The 4Q 2010 inspection identified a finding and an associated Non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," associated with the failure to adhere to welding procedures during a weld repair of the A

Containment Spray Pump lines during the October 2010 Unit 3 RFO. The welders failed to measure preheat and interpass temperatures, as required by procedures. As part of the immediate actions, a stand-down was conducted for welders to reinforce procedural compliance expectations and an extent of condition evaluation was performed. The finding was determined to be of very low safety significance and had been entered into the CAP. As a result, it was treated as an NCV consistent with the NRC Enforcement Policy. This is an example of an issue that was not discovered by the PTN ASME Section XI, Subsections IWB, IWC, and IWD AMP, but is applicable to the program. The appropriate actions were taken to enter the finding into the CAP and reinforce procedural compliance expectations.

NRC Post-Approval Site Inspection for License Renewal Inspection Report, July 12, 2012, Accession No. ML12195A272 (Reference B.3.60): A post-approval license renewal inspection was performed; and no findings were identified as a result of the inspection.

NRC Integrated Inspection Report (4Q 2015), April 6, 2016, Accession No. ML16095A172 (Reference B.3.77): The inspectors conducted an onsite review of the ISI program for monitoring degradation of the RCS boundary, risk-significant piping and component boundaries, and containment boundaries in Unit 3. The inspectors either directly observed or reviewed selected NDEs, as well as the qualifications of the NDE technicians performing the examinations, to evaluate compliance with ASME Code, Section XI and Section V, requirements. The inspectors also either directly observed or reviewed selected welding activities, qualification records, and associated documents to evaluate compliance with ASME Code, Section XI and Section IX requirements. No findings were identified.

4. Program health reports from 2012 through 2017 were reviewed and show a consistent trend of positive program performance through the global indicators of program personnel, infrastructure, implementation, and equipment.

The above OE examples provide reasonable assurance that the ASME Section XI, Subsections IWB, IWC, and IWD AMP is effective for both detecting and trending the aging effects of pressure retaining components. A review of the OE examples showed that, where age-related degradation has been identified, the appropriate corrective actions have been taken to prevent loss of intended function. Frequent audits and NRC inspections provide a high level of insight into the program health. Since there were minimal findings from audits and NRC inspections, there is reasonable assurance that continued implementation of the AMP, with the identified enhancements, will effectively identify and address degradation prior to loss of component intended function.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.2 Water Chemistry

Program Description

The PTN Water Chemistry AMP, formerly a portion of the PTN Chemistry Control Program, is an existing AMP that manages loss of material due to corrosion and cracking due to SCC and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a treated water environment. This AMP includes periodic monitoring of the treated water in order to minimize loss of material or cracking. The PTN Water Chemistry AMP relies on monitoring and control of reactor water chemistry based on industry guidelines contained in Electric Power Research Institute (EPRI) 1014986 (Reference B.3.97), “PWR Primary Water Chemistry Guidelines,” and EPRI 1016555 (Reference B.3.100), “PWR Secondary Water Chemistry Guidelines.”

The PTN Water Chemistry AMP is generally effective in removing impurities from intermediate and high-flow areas; however, NUREG-2191 also identifies those circumstances in which this AMP is to be augmented to manage the effects of aging for SLR. For example, the PTN Water Chemistry AMP may not be effective in low-flow or stagnant-flow areas. Accordingly, in certain cases as identified in NUREG-2191, verification of the effectiveness of this AMP is undertaken to provide reasonable assurance that significant degradation is not occurring and the component intended function is maintained during the SPEO. For these specific cases, the PTN One-Time Inspection AMP (Section B.2.3.20) is used to perform inspections of selected components at susceptible locations in the system to be completed prior to the SPEO. This AMP addresses the metallic components subject to AMR that are exposed to a treated water environment.

This PTN Water Chemistry AMP includes specifications for chemical species, impurities and additives, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice, and pitting corrosion and cracking caused by SCC. Additives are used for reactivity control and to control pH and inhibit corrosion.

This AMP monitors concentrations of corrosive impurities and water quality in accordance with the EPRI water chemistry guidelines to mitigate loss of material, cracking, and reduction of heat transfer. Chemical species and water quality are monitored by in-process methods and through sampling, and the chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples. Chemistry parameter data are recorded, evaluated, and trended in accordance with the EPRI primary and secondary water chemistry guidelines, and maximum levels for various chemical parameters are maintained within the system-specific limits that are consistent with the EPRI primary and secondary water chemistry guidelines.

Any evidence of aging effects or unacceptable water chemistry results are evaluated, the cause identified, and the condition corrected. When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range (or to change the operational mode of the plant) within the time period in the

Nuclear Chemistry Parameters Manual. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling or other appropriate actions are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants, such as chlorides, fluorides, sulfates, and dissolved oxygen, to within the acceptable ranges.

NUREG-2191 Consistency

The PTN Water Chemistry AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M2, “Water Chemistry.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

1. NRC IN 2007-37, "Buildup of Deposits in Steam Generators," discussed primary to secondary leaks that occurred as a result of high cycle fatigue due to flow-induced vibration. The tubes became susceptible to vibration and fatigue as a result of the build-up of deposits on the secondary side of the steam generator which changed the flow conditions in the center of the tube bundle. Contributing factors to the buildup of the deposits were determined to be low secondary side pH (less than 9.6), chemical intrusions (from main condenser cooling water leakage in the secondary system), and the tube support plate hole design (quatrefoil-shaped holes).

   IN 2007-37 was entered into the PTN CAP to assess applicability to PTN. It was determined that the PTN Steam Generators AMP (Section B.2.3.10) includes secondary side inspections to assess the extent of secondary side deposit buildup. In addition, PTN has proactively implemented high volume flushes of the tube bundles and sludge lancing of the tubesheets at each refueling outage. The success of this aggressive approach to deposit removal is evident from the quantities of sludge removed from the secondary side of the steam generators. In addition, Chemistry has made improvements to reduce iron transport to the steam generators. Reduction in iron transport occurred as a result of all copper being eliminated from systems. Components containing copper were systematically replaced over the years, the last of which were replaced via the Engineering Change process as part of the 2012 EPU.

2. NRC IN 2006-27, "Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors," described an event that occurred during a spring 2006 outage at Braidwood where boron deposits were found in the pressurizer surge line area. The leakage originated form the number 52 pressurizer heater at the upper weld between the pressure tube and heater coupling. This determination was based on deposit patterns, deposit chemical analysis, and rouging (i.e., rust) found in the convection cover insulation sleeve for heater number 52. It was noted that rouging could be caused by steam impingement on the stainless steel material. Visual inspection of all 78 pressurizer heaters occurred to determine the extent of condition and it was determined that heater number 52 was the only source of boric acid leakage from the pressurizer. The leaking coupling was removed from the system, the tube plugged, and the coupling was sent for analysis to determine the cause of the failure. Results of laboratory testing determined that the cracking in the sleeve occurred due to circumferentially-oriented IGSCC in the heat affected zone.

   This was entered into the PTN CAP to perform external visual inspections of the pressurizer heater sleeve to heater weld connections. These visual inspections were performed at PTN Unit 4, Seabrook and 15 other Westinghouse plants since the Braidwood event and no new leaks have been identified. A separate action in the PTN CAP documented inspection of PTN Unit 3. As with the other units and plants, no new leaks were identified at PTN Unit 3.

<u>Site-Specific Operating Experience</u>

The following review of site-specific operating experience prior to and during the first PEO provides objective evidence that the PTN Water Chemistry AMP effectively manages aging effects so that the intended functions of SCs within the scope of the Water Chemistry AMP will be maintained during the SPEO.

1. During 2015, the following conditions were identified on Unit 3:

   - In March of 2015, condensate pump dissolved oxygen was cycling approximately every 20 minutes due to the makeup from the demineralized water storage tank (DWST). Hotwell dissolved oxygen also showed the same cycling and correlated with the condensate pump cycling. To address the issue, chemistry personnel maintained hydrazine injection at a higher concentration than normally required. This action was effective in maintaining dissolved oxygen levels.

   - In June of 2015, a low hydrazine instrument reading resulted in an unexpected alarm in the Control Room. Initial review showed no chemistry action level was entered. A decreasing trend was observed by Chemistry, and preventive action was taken in the form of adjusted chemistry to maintain adequate hydrazine margin above the alarm setpoint.

2. In September of 2016, while performing secondary trend reviews, a decreasing trend was identified on the Unit 3 and 4 feedwater hydrazine levels. Upon investigation, the on-shift chemist noticed all five hydrazine chemical addition tanks were slowly overflowing into the chemical addition berm. The Chemistry technician immediately increased pump speed to increase the hydrazine concentration, effectively returning the hydrazine to proper levels.

3. In 2016, an external evaluation provided an area for improvement related to the chemistry program. Chemistry technicians inconsistently applies fundamental chemistry standards and laboratory work practices. This resulted in exceeding chemistry limits for the chilled water and feedwater system. As a result of this identified area for improvement, training was provided to the department on chemistry fundamentals. Posters were hung in key areas to enforce these fundamentals. Other utilities chemistry programs that had demonstrated strengths were benchmarked and the results of these benchmarking trips were used to enhance the chemistry program. Daily fundamentals topics are provided to the technicians by the supervisors to ensure adequate performance of job functions.

4. The following are summaries of recent internal audits of the PTN Water Chemistry Control Program:

    - An audit team reviewed the PTN Water Chemistry Control AMP in 2012. The audit team concluded that on an overall basis, the requirements of the PTN Water Chemistry AMP are satisfactorily addressed by procedures and the implementation of those procedures was effective. Areas of satisfactory performance included chemistry control, sampling activities, chemistry monitoring, data analysis and trending.

    - An audit team, including a peer technical specialist (Chemistry QC Supervisor - V.C. Summer Nuclear Station), reviewed the PTN Water Chemistry AMP in 2014. It was determined that satisfactory performance was observed for methods of chemistry control to achieve long-term reliable equipment performance as observed through sampling activities, analytical methods, calibration and control of laboratory instruments, and reagent control.

      A need for improvement was noted with respect to the following: Chemistry focused on clean-up of RCS chlorides as the corrective action upon lithium addition rather than prevention of the chloride release. In 2011 during U4 startup after refueling, chlorides were released to the RCS water after addition of lithium in accordance with Chemistry procedures. Lithium had been added in batches. The corrective action focused on clean-up of the chlorides. Feed and bleed, and filtration through resins were used to dilute the water and reduce the chloride level. However, no change to the procedure or process was made at that time to prevent the release of chlorides in the future. Following the 2014 U4 refueling outage, lithium was again added in batches, which again resulted in chloride release once the lithium concentration reached a critical value. Dilution of the RCS chlorides was again the corrective action.

This need for improvement was evaluated in the PTN CAP. The conclusion of this evaluation was that RCS chloride releases can't be prevented in elevated boron/pH conditions; however, efforts should be made to minimize the impacts by incorporating industry best practices for alternative startup strategies to minimize iron transport to the steam generators. Therefore, an additional action was entered into the CAP to perform formal benchmarking to identify improvement opportunities to enhance primary chemistry outage performance to include demineralizer performance and crud burst management. Additional benchmarking was performed to gain further insights to chemistry start-up and shutdown strategies. This benchmarking conducted in 2015 identified multiple opportunities to enhance demineralizer performance by minimizing RCS chloride releases during start-up, as well as possible enhancements to crud burst management strategies to minimize crud peak activity in upcoming outages and optimize clean-up to ultimately reduce dose to personnel. These enhancements have either been incorporated, implemented, or entered into the PTN CAP.

This audit also noted that the corrective actions implemented from the 2012 Water Chemistry audit were in accordance with CAP procedure requirements.

- An audit team reviewed the PTN Water Chemistry Control AMP in 2016. As with the audit in 2014, it was determined that satisfactory performance was observed for methods of chemistry control to achieve long-term reliable equipment performance as observed through sampling activities, analytical methods, calibration and control of laboratory instruments, and reagent control. The audit team concluded that overall, the implementation of the Water Chemistry Control AMP and associated processes were satisfactory.

5. The following information was obtained from the PTN Program Health Reports:

    - In the third quarter 2017 (Q3-2017) system health report for Water Chemistry, an independent reviewer in a December 2016 evaluation determined that Chemistry performance had improved, Chemistry leaders improved cross-functional teamwork and alignment within the department to achieve station goals in chemistry performance. It was determined that Chemistry personnel effectively control primary, secondary, auxiliary and closed cooling water parameters within goals and limits.

- The PTN Water Chemistry Program Health Reports note that Water Chemistry program has been GREEN since the first quarter of 2016.

6. The following are summaries of recent internal assessments of the Water Chemistry AMP:

    - In 2017, an internal assessment was performed and was documented in the PTN CAP. This assessment was performed to assess chemistry control of Unit 3 on startup following refueling outage 3R29. Specific items addressed were as follows:

- Feedwater iron (Fe) concentration levels.

- Secondary contamination.

- Primary system startup chemistry (oxygen removal during start-up, demineralizer operation, lithium (Li) management during start-up).

- Start-up lessons learned.

- The start-up was determined to be very successful for the following reasons:

  - The start-up iron reading was 3.0 ppb when taken a week after reaching 30 percent power.

  - Secondary contamination levels were low during start-up.

  - For primary system start-up, de-oxygenating of the pressurizer and RCS required several hydrazine chemical additions. Ultra-low chloride resin was used in the demineralizer for startup, which allowed starting up of the primary system without an increase in RCS chloride levels. Therefore, feed and bleed was not required to reduce chloride levels, which assisted with lithium management.

7. An administrative review of the Secondary Chemistry Optimization Plan was completed in 2016 and determined that the PTN chemistry control regimes would remain unchanged. This administrative review fulfilled the EPRI periodic review requirement.

8. An administrative review of the Primary Chemistry Optimization Plan was completed in 2017 and determined that the PTN chemistry control regimes would remain unchanged. This administrative review fulfilled the EPRI periodic review requirement.

The OE relative to the PTN Water Chemistry AMP provides objective evidence that the existing program will continue to effectively detect and trend aging effects. A review of the operating experience examples shows that inspections have been effective in discovering abnormal conditions and responding to the conditions with corrective actions prior to resulting adverse water chemistry conditions and/or loss of component intended function. Program improvements have been made due to the review of OE events to improve system performances, and continuation of this OE review process is maintained for future program improvements. Periodic assessments of the Water Chemistry AMP are performed to identify areas that need improvement to maintain the quality performance of the program and steps are taken to improve those areas of the program.

Therefore, there is confidence that continued implementation of the PTN Water Chemistry AMP will continue to effectively identify and address degradation prior to component loss of intended function.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Water Chemistry AMP provides reasonable assurance that the effects of aging are adequately managed so that the intended functions of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.3 Reactor Head Closure Stud Bolting

Program Description

The PTN Reactor Head Closure Stud Bolting AMP is an existing AMP for subsequent license renewal (SLR), related to and currently part of the ASME Section XI, Subsections IWB, IWC and IWD, portion of the PTN ISI Program. This AMP provides (a) inservice inspection (ISI) in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB 2500-1; and (b) preventive measures to mitigate cracking. This AMP is in accordance with the regulatory position delineated in NRC RG 1.65 (Reference B.3.21), "Materials and Inspections for Reactor Vessel Closure Studs." The scope of this AMP includes:

- Closure head nuts
- Closure studs
- Threads in the RPV flange
- Closure washers and bushings

Through inspections performed as part of the PTN ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1), the reactor head closure stud bolting is managed for aging effects due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC), and loss of material due to corrosion or wear. In accordance with the 2007 edition of the ASME Code Section XI, with 2008 addenda, the Subsection IWB categorization and methods for ISI are listed in Table B-5 below:

Table B-5
ASME Code Section XI, Subsection IWB Inspection Methods

Examination Category	Item Number	Description of Components Examined	Examination Method(s)
B-G-1 pressure retaining bolting greater than 2 inches in diameter	B6.10	Closure head nuts	VT-1 visual
	B6.20	Closure studs	Volumetric or surface
	B6.40	Threads in flange	Volumetric
	B6.50	Closure washers, bushings	VT-1 visual

This AMP monitors material conditions and imperfections and detects loss of material by performing visual inspections (VT-1), surface examinations (liquid penetrant and magnetic particle), and volumetric examinations (ultrasonic, radiography and eddy current) in accordance with the requirements specified in Table IWB-2500-1. The specific type of inspection to be performed for each of the different bolting components is listed in the PTN ISI Program Plan (Reference B.3.143). Components are examined for evidence of operation-induced flaws (cracking, pitting) using volumetric and surface techniques. The VT-1 visual inspection is used to detect cracks, symptoms of wear, corrosion, or physical damage. The extent and frequency of inspections is specified in Table IWB-2500-1, as modified in accordance with the PTN ISI Program Plan.

Appropriate preventive measures have been used for the reactor head closure stud bolting based on site OE and best practices. However, the possible measures (precautions) have not been formally documented. The appropriate preventive measures for PTN will be documented in the pertinent procedure, guideline or plan prior to entering the SPEO. PTN took one exception to preventive measure (Element 2 (d)). See below for details.

This AMP ensures that the frequency and scope of examination of the reactor head closure stud bolting is sufficient so that the aging effects are detected before the component(s) intended function(s) would be compromised or lost. Inspections are performed in accordance with the inspection intervals specified by IWB-2412 Inspection Program B and Table IWB-2412-1, as reflected in the PTN ISI Program Plan. These examinations are scheduled in accordance with the PTN ISI Program Plan and will be continued during the SPEO.

The acceptance criteria associated with this AMP, provided in the PTN ISI Program Plan, are based on the acceptance standards for the inspections identified in Subsection IWB for the reactor head closure stud bolting. Table IWB-2500-1 identifies references to acceptance standards listed in IWB-3500. Items with examination results that do not meet the acceptance standards are subject by this AMP and the PTN ISI Program Plan to acceptance by evaluation, repair, or replacement in accordance with Subsections IWB, IWA-4000, and IWA-6000. In addition, the material inspection and maximum yield strength information provided in the regulatory position of NRC RG 1.65 will be included in the program, for completeness, prior to entering the SPEO. When areas of degradation are identified, an engineering evaluation is performed to determine if the component is acceptable for continued service, or if repair or replacement is required. The engineering evaluation includes probable cause, the extent of degradation, the nature and frequency of additional examinations, and whether repair or replacement is required.

NUREG-2191 Consistency

The PTN Reactor Head Closure Stud Bolting AMP will be consistent, with exception and enhancements, with the 10 elements of NUREG-2191, Section XI.M3, “Reactor Head Closure Stud Bolting.”

Exceptions to NUREG-2191

NUREG-2191 recommends, as a preventive measure that can reduce the potential for SSC or IGSCC, using bolting material for the reactor head closure studs that have an actual measured yield strength limited to less than 1,034 megapascals (MPa) (150 kilo pounds per square inch (ksi)) (NUREG-1339). PTN closure stud bolting is considered high strength steel (Section 3.1.2.1.3), and PTN is taking exception to Element 2(d), Preventive Actions. The exception is acceptable because PTN meets all other program element requirements for reactor head closure stud bolting and will enhance the program so that replacement bolts are limited to a yield strength of 150 ksi. In addition, PTN performs volumetric inspection of high-strength bolting for cracking under the PTN ASME Section XI, Subsection IWF AMP.

Enhancements

The PTN Reactor Head Closure Stud Bolting AMP will be enhanced for alignment with NUREG-2191, as discussed below. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Revise the procurement requirements for reactor head closure stud material to ensure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi and revise procedures to note that lubricants cannot contain molybdenum disulfide to inhibit corrosion.
7. Corrective Actions	Items with examination results that do not meet the acceptance standards are subject to acceptance by evaluation, repair or replacement in accordance with Subsection IWB. In addition, the material inspection and maximum yield strength information provided in the regulatory position of RG 1.65 (Reference B.3.21) will be included in the program, for completeness, prior to entering the SPEO.

Operating Experience

Industry Operating Experience

Other than RG 1.65, there has been no new industry OE for reactor head closure stud bolting since PTN entered the current PEO. RG 1.65 provides guidance on material plating, lubricant, and mechanical properties for reactor head closure bolting, which is incorporated into NUREG-2191 and makes up the preventive actions recommended in Element 2 of the XI.M3 Evaluation and Technical Basis. The PTN Reactor Head Closure Stud Bolting AMP will be making the enhancements and exceptions as described in the sections above in consideration of the guidance provided in RG 1.65.

Site-Specific Operating Experience

The following review of site-specific OE, including ARs and system health reports, provides examples of how PTN is managing aging effects associated with the Reactor Head Closure Stud Bolting AMP.

1. In April 2016, it was found that a reactor vessel head stud did not meet the elongation criteria after tensioning was complete, and as a result a CAP item was created. A stud exceeded the Level I elongation acceptance criterion, which considers only the elongation of the subject stud, by 1 mil. The procedure allows a Level II elongation criterion, which considers the average elongation of the subject stud and the adjacent studs. It was determined that the stud met the Level II elongation criterion and was thus acceptable for continued use, and the CAP item was closed.

2. During the Unit 3 Cycle 26 RFO in the spring of 2012, performance of the ASME Section XI Inservice Inspection of reactor head bolting led to the discovery of corrosion on the lower threads of three reactor head closure nuts. One of the nuts also had nicks in the top two threads. Visual inspection was performed on the mating studs, and no issues were identified. An evaluation was performed to determine possible causes of the corrosion and determine a method for mitigating future damage. The evaluation included inspection of all 58 reactor head closure nuts. No visual evidence of boric acid leakage was documented in the evaluation. Additionally, it was observed that no industry OE identified the lubricant in use as corrosion-causing. The evaluation concluded that the corrosion was superficial and could be easily removed. Small gouges and scratches exposing the raw material were also seen with no corrosion. The most likely cause of the corrosion was determined to be another material deposited on the threads during installation. A like-for-like replacement of the three nuts was performed in the Cycle 26 RFO.

3. Health of the PTN ASME Section XI Inservice Inspections, IWB, IWC, and IWD AMP is reported quarterly. Health reports for the period from 2012 through 2017, that includes the PEO, of the PTN ASME Section XI Inservice Inspections, IWB, IWC, and IWD AMP show a consistent trend of positive program performance, and have:

    a. GREEN (i.e., healthy) status with satisfactory findings for all health indicators.

    b. No equipment failures due to inadequate ISI.

    c. No implementation issues related to inspections, surveillance, or work order productivity.

The above examples provide reasonable assurance that the Reactor Head Closure Stud Bolting AMP is effective for both detecting and trending the aging effects of reactor head bolting components. A review of the operating experience examples showed that, where age-related degradation has been identified, the appropriate measures have been taken or specified to prevent loss of intended function. Frequent audits and NRC inspections provide a high level of insight into the program health. Since there were minimal findings from audits and NRC inspections, there is reasonable assurance that continued implementation of the AMP, with the identified enhancements, will effectively identify and address degradation prior to loss of component intended function. To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the

AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Reactor Head Closure Stud Bolting AMP, with exception and enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.4 Boric Acid Corrosion

Program Description

The PTN Boric Acid Corrosion AMP, previously the PTN Boric Acid Wastage Surveillance Program, is an existing AMP that manages the aging effects of loss of material and mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. This AMP relies, in part, on the response to NRC Generic Letter (GL) 88-05 (Reference B.3.32), as documented in FPL letter L-88-239 (Reference B.3.135), to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. The AMP also includes inspections, evaluations, and corrective actions for all components, including electrical, subject to AMR that may be adversely affected by some form of borated water leakage. The effects of boric acid corrosion on reactor coolant pressure boundary materials in the vicinity of nickel-alloy components are also addressed by the PTN AMP that is associated with NUREG-2191, Section XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)."

In addition, the PTN Boric Acid Corrosion AMP includes provisions to initiate evaluations and assessments when leakage is discovered by other plant activities not associated with this AMP. This AMP follows the guidance described in Section 7 of WCAP-15988-NP (Reference B.3.149), "Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors."

The PTN Boric Acid Corrosion AMP covers any susceptible structures and components (SCs) on which boric acid corrosion may occur and electrical components onto which borated reactor water may leak. This AMP includes provisions in response to the recommendations of NRC GL 88-05 (Reference B.3.32). This AMP provides the following:

a. Determination of the principal location of leakage;

b. Examinations and procedures for locating small leaks, and;

c. Engineering evaluations and corrective actions to provide reasonable assurance that boric acid corrosion does not lead to degradation of the leakage source or adjacent SCs.

This AMP is credited with managing boric acid corrosion for SCs located adjacent to or in the vicinity of borated water systems and susceptible to leakage (or spray). The PTN Boric Acid Corrosion AMP minimizes exposure of susceptible materials to borated water by frequent monitoring of the locations where potential leakage could occur and timely cleaning and repair if leakage is detected. The removal of concentrated boric acid, boric acid residue, and elimination of borated water leakage, mitigates corrosion by minimizing the exposure of the susceptible material to the corrosive environment. In addition, evaluations associated with this AMP consider preventive actions, including, but not limited to, the consideration of engineering changes, procedure revisions, or both, which would:

a. Reduce the probability of leaks at locations where they may cause corrosion damage, and

b. Entail the use of corrosion resistant materials or the application of protective coatings or cladding.

Boric acid residue and borated water leakage are directly related to the degradation of components. This AMP monitors the effects of boric acid corrosion on the intended function of the component by detection of leakage as required by GL 88-05, including guidelines for locating small leaks, conducting examinations, and performing evaluations. Leakage identification is primarily by visual personnel observations and scheduled inspections and surveillances; however, this identification is supplemented, as appropriate, using methods such as RCS water inventory balancing and using Reactor Building Radiation Monitors capable of detecting RCS pressure boundary leakage. The monitors are extremely sensitive to leakage from the RCS pressure boundary, due to the sealed nature of the PTN Containment Buildings. The RCS leak rate associated with the RCS inventory balancing is calculated every shift as required by PTN TS (Reference B.3.147), Section 4.4.6.2.1.c, and these leak rate calculations can help identify new leaks. The procedures associated with this AMP will also be enhanced no later than six months prior to entering the SPEO, as discussed below.

Degradation of the component due to boric acid corrosion cannot occur without leakage of coolant containing boric acid. Conditions leading to boric acid corrosion, such as crystal buildup and evidence of moisture, are readily detectable by visual inspections. Visual inspections are performed on external surfaces in accordance with program procedures. Locations that cannot be inspected or accessed due to any obstructions or As-Low-As-Reasonably-Achievable (ALARA) considerations are documented and reported to responsible management and the Boric Acid Corrosion Program Owner, and should be identified for future resolution. If it appears boric acid may have entered insulation and spread internally to locations that are not visible, a Work Request is initiated to have the insulation removed in order to examine the extent of the condition. Program procedure(s) are developed based on the response to and guidance provided in NRC GL 88-05 and include guidelines for locating small leaks, conducting examinations, and performing engineering evaluations. Additionally, the PTN Boric Acid Corrosion AMP includes appropriate interfaces with other site programs, such as Chemistry, Operations, Work Control, and Engineering. Borated water leakage that is encountered by means other than the monitoring and trending established by this program is evaluated and corrected.

The PTN Boric Acid Corrosion AMP provides monitoring and trending activities as delineated in NRC GL 88-05, timely evaluation of evidence of borated water leakage identified by other means, and timely detection of leakage by observing boric acid crystals during normal plant walkdowns and maintenance. This AMP maintains a database of all components with evidence of boric acid leakage (e.g., active leaks, boric acid deposits, and corrosion-related discoloration) for the purpose of tracking corrective maintenance and trending of leakage-related information. The nature of the database makes it easier to identify chronic/repeat leakage locations and targets susceptible to corrosion. All indications of boric acid leakage (e.g., detected borated water leakage, white/discolored boric acid crystal buildup, or rust-colored deposits) are screened to determine if more detailed evaluations of the leaking component or associated targets (susceptible materials at risk of borated water exposure) are warranted (i.e., a "Boric Acid Corrosion Control Evaluation"). When a Boric Acid Corrosion Evaluation is required, Engineering evaluates and recommends a corrective action and monitoring frequency. PTN also prepares quarterly system health reports for the Boric Acid Corrosion program that tracks and trends the number of active leaks and size of maintenance backlog. This is further discussed in the operating experience section below.

Borated water leakage and areas of resulting boric acid corrosion are evaluated and corrected in accordance with the applicable provisions of NRC GL 88-05 and the PTN CAP. Any detected boric acid crystal buildup or deposits are to be cleaned. Per the NRC GL 88-05 recommendation, an objective of the PTN Boric Acid Corrosion AMP is to ensure that corrective actions are taken to prevent recurrences of degradation caused by borated water leakage. These corrective actions consider the inclusion of any modifications to be introduced in the present design or operating procedures of the plant that (a) reduce the probability of reactor coolant leaks at locations where they may cause corrosion damage and (b) entail the use of suitable corrosion resistant materials or the application of protective coatings or claddings.

NUREG-2191 Consistency

The PTN Boric Acid Corrosion AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M10, "Boric Acid Corrosion."

Exceptions to NUREG-2191

None.

Enhancements

The PTN Boric Acid Corrosion AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements will be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Include other potential means to help in the identification of borated water leakage, such as: • Humidity monitors (for trending increases in humidity levels due to unidentified RCS leakage) • Temperature monitors (for trending increases in room/area temperatures due to unidentified RCS leakage) • Containment air cooler thermal performance (for corroborating increases in containment atmosphere temperature or humidity with decreases in cooler efficiency due to boric acid plate out) These results will be reviewed on a yearly basis.

Operating Experience

Industry Operating Experience

As described below, industry operating experience indicates that boric acid leakage can cause significant corrosion damage to susceptible systems and components in nuclear power plants, including in areas that are difficult to access and inspect.

By way of background, NRC Bulletin 2002-01, issued on March 18, 2002, required information to be sent to the NRC regarding the material condition of the reactor pressure vessel head and the remainder of the RCS pressure boundary. In response to this Bulletin, FPL completed bare metal visual inspections of the reactor vessel head in PTN Unit 4 in March of 2002 and PTN Unit 3 in October 2001. The results of these initial inspections showed that the reactor vessel heads were free of any leakage coming from the reactor vessel head penetrations at each unit and no boron accumulations were identified. In addition, in response to this Bulletin, FPL reviewed its ongoing reactor vessel head inspection program and concluded that all reactor coolant pressure boundary components inside containment (including the reactor vessel heads) that could be affected by boric acid wastage degradation are within the program and adequately managed consistent with the current licensing basis. These ongoing inspections provide reasonable assurance that leakage has been and will continue to be detected on the reactor vessel head long before age-related degradation could result in loss of intended function.

Further, NRC Order EA-03-009, issued on February 11, 2003, established interim inspection requirements for reactor pressure vessel heads and head penetration nozzles of pressurized water reactors. FPL performed inspections of required components for PTN Unit 4 during the October 2003 refueling outage. Based on the results of the reactor pressure vessel head visual examination, reactor pressure vessel head penetration nozzles ultrasonic examinations and leak path assessments (including ECT of the vent), FPL concluded that the alloy 600 reactor pressure vessel head penetration nozzles were not degraded, and no wastage of the reactor pressure vessel head had occurred. These inspections for PTN Unit 3 were performed during the March 2003 refueling outage. Based on the results of the reactor pressure vessel head visual examination, reactor pressure vessel head penetration nozzles ultrasonic examinations and leak path assessments (including liquid penetrant of the vent), FPL concluded that the alloy 600 reactor pressure vessel head penetration nozzles were not degraded, and no wastage of the reactor pressure vessel head had occurred. This inspection is performed on each unit every refueling outage. Reactor head inspections are performed in accordance with ASME Section XI ISI program.

Also in 2003, NRC Bulletin 2003-02, issued on August 21, 2003, requested information on the reactor pressure vessel (RPV) lower head penetration inspection program, including plans for future inspections. NRC Bulletin 2003-02 also requested that within 60 days of plant restart following the next inspection of RPV lower head penetrations, the licensee submit a summary of the inspection performed. FPL performed inspections for PTN Unit 3 during the October 2004 refueling outage. The 50 RPV lower head penetrations for PTN Unit 3 were examined by the ultrasonic method, without limitation, to a volume that met or exceeded the committed examination volume. No service induced degradation or crack like indications were identified in the 50 penetrations. A boric acid walkdown inspection of the cavity and underside of the reactor vessel, with the insulation in place, did not reveal any evidence of nozzle leakage. These inspections were performed for PTN Unit 4 during the October 2003 refueling outage. Based on the results of the visual examinations, there was no evidence of leakage from the 50 RPV lower head penetrations or wastage of the RPV lower head at PTN Unit 4. This inspection is performed on each unit every refueling outage in accordance with the ASME Section XI ISI AMP (Section B.2.3.1).

There is also relevant industry operating experience from the Dominion North Anna Unit 2 reactor. The North Anna Unit 2 reactor vessel head was replaced in January 2003. The pre-existing North Anna Unit 2 CRDM assemblies were transferred onto the new Framatome reactor vessel head. At the completion of the third cycle, after the new Framatome head was installed on the vessel at North Anna Unit 2, the Dominion visual inspection identified a small accumulation of boric acid on the seal weld of a spare CRDM penetration. FPL reviewed this OE. The PTN reactor vessel heads were replaced in 2004 for Unit 3 and 2005 for Unit 4. However, new CRDMs were installed on the new vessel heads at PTN. Inspections of the vessel heads at PTN Units 3 and 4 occur every refueling outage and have not identified any boric acid leakage or buildup on the vessel head or CRDMs. As a result, review of this operating experience determined that no changes were needed to the PTN Boric Acid Corrosion program.

Additional operating experience at North Anna Unit 2 in 2007 pertained to the identification of a white residue, believed to be boric acid, at the pressurizer heater sleeves. Subsequent chemical analysis determined that the white substance was not boric acid, but a flux leftover from the soldering process. An inspection of the heater sleeves for leakage was conducted at PTN Units 3 and 4 and no signs of boric acid or any other white substance was noted. The review determined that no changes were needed to the PTN Boric Acid Corrosion program.

Site-Specific Operating Experience

The following review of site-specific operating experience during the first PEO, including past and ongoing corrective actions as discussed in the System Health Report section below, provides objective evidence that the Boric Acid Corrosion AMP is effective at the identification, remediation, and management of aging effects so that the intended functions of SCs within the scope of the Boric Acid Corrosion AMP will be maintained during the SPEO.

1. Following bare metal inspections of the reactor vessel head in 2014, a boric acid evaluation documented boric acid residue identified on the Unit 4 closure head at one CRDM nozzle and near the head vent line. The 2014 inspections of the Unit 3 closure head also observed boric acid near two core exit thermocouple nozzle assemblies and six CRDM nozzles. In each case, these indications were compared with similar observations that had been noted in prior outage inspections. It was determined that the leakage occurs during head removal/installation activities. Reviews of collected ultrasonic data confirmed that no flaws exist in any of the subject penetrations. Though there has been no evidence of cracking in the subject penetrations, findings from the inspections outlined

above would lead to corrective actions under the PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP (Section B.2.3.5) prior to loss of component intended function.

2. In April of 2015, a minor accumulation of dry boric acid was identified during a Boric Acid Corrosion program walkdown on the Unit 3 A RHR pump discharge sample valve. The condition was entered into the PTN CAP and included in the ECCS Leak List for repair. The source was determined to be a packing leak. Repairs were made and no further leakage has occurred. This component is part of the Boric Acid Corrosion program area walkdowns.

3. In June of 2015, wet boric acid was identified on the packing of the Unit 4 B Charging pump discharge isolation valve during a Boric Acid Corrosion program walkdown. The condition was entered into the CAP and the resultant evaluation determined that it was not considered to be pressure boundary leakage. The boric acid was cleaned and the valve was repacked to prevent further leakage. No further leakage has occurred. This component is part of the Boric Acid Corrosion program area walkdowns.

4. In June of 2015, an active leak was found on valve 4-239D during Boric Acid Corrosion program walkdowns. The condition was entered into the CAP. The valve was cleaned and re-torqued / consolidated packing. No further leakage has occurred. This component is part of the Boric Acid Corrosion program area walkdowns.

5. In August of 2015, dry boric acid was identified during Boric Acid Corrosion program walkdowns on the Unit 4 RCP A seal injection flow indicator. The condition was entered into the CAP. The source of the leakage was determined to be at the threaded manifold adapters. The affected connections were repaired or replaced as required. No further leakage has occurred. This component is part of the Boric Acid Corrosion program area walkdowns.

6. In October of 2015, dry boric acid residue was found during Boric Acid Corrosion program walkdowns at two pressure fittings at the Unit 3 seal table. The condition was entered into the CAP. The fittings were re-torqued to prevent future leakage. No further leakage of the pressure fittings has occurred. This component is part of the Boric Acid Corrosion program area walkdowns.

7. In April of 2016, during Boric Acid Corrosion program walkdowns for RCS leakage at normal operating pressure and temperature, active leakage was found at the H-3 location of the Unit 4 flux mapper seal table. The condition was entered into the CAP and the leakage was monitored per the evaluation. All the seal table components and fittings are made of stainless steel material (type 304 and 316). Stainless steel is not susceptible to boric acid corrosion; therefore, the active leakage will not affect the other components in the seal table. The leakage reduced over time as the components thermally stabilized. The H-3 location on the seal table is was scheduled to be re-inspected in the next Unit 4

refueling outage scheduled for October 2017, with no further leakage noted at the H-3 location. The seal table is part of the Boric Acid Corrosion program area walkdowns.

The following additional examples of site-specific OE provide objective evidence that activities other than those established specifically to detect borated water per the Boric Acid Corrosion program are also effective in identifying, evaluating, and correcting borated water leaks prior to loss of component intended function. In the examples given below, Boric Acid Corrosion program site engineering would be contacted if signs of boric acid leakage were discovered. Boric Acid Corrosion program site engineering assists in categorization of the leak and assesses its significance for corrective action purposes.

1. In November 2006, a small hole was found in the floor of the Unit 4 reactor cavity sump liner plate. The corrosion was attributed to water trapped behind the liner plate when high pressure water was used to cut a hole in the Containment building to facilitate reactor vessel head replacement. Bulges in the liner plate provided a path for retained water to collect beneath the reactor sump. The hole was plugged and welded and the area was left with stainless steel on stainless steel. The repair was leak tested successfully. Periodic inspections of sump areas were added to the ASME Section XI Subsection IWE AMP (Section B.2.3.30) program so that future degradation can be identified before the condition adversely impacts structural steel components or coatings. It appeared to be attributed to Boric Acid.

2. During the 2010 maintenance and refueling outage for PTN Unit 3, a scheduled visual examination of the containment liner plate in the sump area revealed significant corrosion in a localized region of the vertical wall section, immediately adjacent to the concrete floor. Further investigation with visual and volumetric inspection methods revealed that the corrosion degradation initiated on the inside surface of the liner plate and that localized repairs were required. There were multiple contributing causes that included a number of programmatic issues, including a lack of boric acid inspections in this area. The root cause evaluation (for extent-of-condition) determined Unit 4 had similar issues. A review of the industry OE revealed this to be the first containment liner plate degradation event attributed to boric acid corrosion. In accordance with corrective actions, welding repairs were performed on both units along with the application of a coating system suitable for immersion service on the liner plate in the lower region of the reactor pit area. No additional boric acid findings have been identified since this timeframe. Visual inspection of the containment liner plate is part of the ASME Section XI Subsection IWE AMP (Section B.2.3.30).

3. During the November 2015 refueling outage for Unit 3 and the April 2016 for refueling outage for Unit 4, Remote Bare Metal Visual examination of 50 bottom-mounted instrumentation (BMI) nozzle penetrations from the outside surface of the reactor vessel lower head was performed per the ASME Section XI Subsection IWE AMP (Section B.2.3.30). The examinations performed revealed 47 (Unit 3) and 50 (Unit 4) relevant indications of staining and discoloration in the examination region of the BMI nozzles. Although there was no dry boric acid identified, the stains from the cavity seal

leakage made contact with carbon steel or low alloy steel which consists of the lower reactor head surface including the bottom-mounted nozzles (BMN) and surrounding areas. Due to the leakage making contact with these areas, corrosion could have been present; however; there was no evidence of corrosion damage to the component (vessel) or other components affected by the leakage. The condition was entered into the CAP. After pressure cleaning, the visual data collected during the outages were compared to the visual inspection results from previous examinations, with no changes noted confirming the continued absence of corrosion.

Regulatory Audits and Inspections

1. NRC Integrated Inspection Reports for 4Q 2010, 2Q 2011, 1Q 2012, 4Q 2012, 2Q 2014, 4Q 2014, 2Q2 016, and 2Q 2017, Accession Nos. ML110280004, ML112082835, ML11117A299, ML13030A208, ML14212A253, ML15030A278, ML16225A526 and ML17223A012, respectively.

   During the inspections documented in the above listed inspection reports, the inspectors reviewed the Boric Acid Corrosion program activities to ensure implementation of commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary," and applicable industry guidance documents. The inspectors also interviewed the Boric Acid Corrosion program owner and conducted an independent walkdown of the reactor building to evaluate compliance with Boric Acid Corrosion program requirements and verify that degraded or non-conforming conditions, such as boric acid leaks identified during the containment walkdown, were properly identified and corrected in accordance with the Boric Acid Corrosion AMP and CAP.

   The inspectors reviewed a sample of engineering evaluations and AR corrective actions for compliance with ASME Section XI. The inspectors also conducted an independent walkdown to evaluate compliance with the Boric Acid Corrosion program requirements, and verified that degraded or non-conforming conditions, such as boric acid leaks, were properly identified and corrected in accordance with the Boric Acid Corrosion AMP and CAP.

   No findings were identified as a result of these inspections.

2. PTN - NRC Integrated Inspection Report 4Q 2015, April 6, 2016 (Accession No. ML16095A172)

   Resident inspectors and specialist inspectors from the Region II office reviewed the FPL boric acid corrosion control program activities to determine if the activities were implemented in accordance with the commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," and applicable industry guidance documents. Specifically, the inspectors performed an onsite records review of procedures, and the results of the licensee containment walkdown inspections performed during the October 2015 RFO.

The inspectors also interviewed the Boric Acid Corrosion program owner, conducted an independent walkdown of containment to evaluate compliance with the Boric Acid Corrosion program requirements, and verified that degraded or non-conforming conditions, such as boric acid leaks, were properly identified and corrected in accordance with the Boric Acid Corrosion AMP and CAP.

The inspectors reviewed selected engineering evaluations completed for evidence of boric acid leakage, to determine if the evaluations properly applied applicable corrosion rates to the affected components; and properly assessed the effects of corrosion induced wastage on structural or pressure boundary integrity in accordance with the licensee procedures.

The inspectors also reviewed selected condition reports (CRs) and associated corrective actions related to evidence of boric acid leakage, to evaluate if the corrective actions completed were consistent with the requirements of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI.

No findings were identified

These examples of regulatory audits and inspections provide further objective evidence that the Boric Acid Corrosion program is effective in identifying, evaluating, and correcting borated water leakage prior to loss of component intended function.

<u>System Health Reports</u>

A review of quarterly system health reports issued from Q1 2012 to Q3 2017 was conducted to ascertain Boric Acid Corrosion program performance during the PEO.

As noted in the 2013 Boric Acid Corrosion system health reports, there were a high number of backlogged corrective action maintenance items involving boric acid leaks. In response to this finding, FPL implemented numerous corrective actions to dedicate maintenance resources in a concerted effort to reduce the backlog.

In 2014, FPL made further improvements to the Boric Acid Corrosion program based on industry benchmarking results and additional Fleet Program Owner process modifications. The Boric Acid Corrosion program required continued management attention and further improvement though 2016. In Q4 of 2016, program health moved to GREEN based on the reduced corrective action maintenance backlog. This was attributed to the following:

- The timely discovery of boric acid leaks at PTN has been improved with Boric Acid Corrosion program site engineering performing the area walkdowns.
- The boric acid backlog has been reduced by Maintenance.

- The Boric Acid Corrosion program database has proven effective for tracking boric acid leaks and classifying Work Requests and Work Orders (that require a Boric Acid Corrosion status).

- Timely self-assessments are conducted and benchmarking is consistently being performed with peer to peer interface and INPO involvement in the development of metrics.

In 2017, program health declined slightly. This determination is based on the number of active boric acid leaks and an increase in the boric acid backlog with some leaks that require cleaning open for long periods (as detailed in the 2017 Q1 through Q3 health reports). To improve system health, the Boric Acid Corrosion program plans to implement a strategy whereby inactive leaks assessed as inconsequential by Boric Acid Corrosion program site engineering will allow them to be cleaned only without additional WO or AR processing. This fix-it-now strategy is expected to streamline the remediation process for inactive, inconsequential leaks while maintaining the overall high quality of the Boric Acid Corrosion program. This strategy is being added to new Boric Acid Corrosion program fleet procedure.

The above review of quarterly system health reports shows that the Boric Acid Corrosion program has matured in a positive direction, as the unacceptable number of active boric acid leaks has decreased. In 2017, the station involvement in identification of boric acid leaks has increased, and on-going improvements to the program through improved metrics and efficiencies in the remediation of inactive, inconsequential leaks. Therefore, there is sufficient confidence that continued implementation of the Boric Acid Corrosion program will effectively identify and address degradation prior to component loss of intended function.

Enhancements to the AMP have been identified and implemented as a result of OE (procedure enhancements, to be completed prior to entering the SPEO). An example of the AMP being enhanced by OE is the following: the use of humidity and temperature monitors (for Element 3, Parameters Monitored & Inspected), for trending increases in humidity and temperature levels, as evidence of unidentified RCS leakage). OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Boric Acid Corrosion AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

Program Description

The PTN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP is an existing AMP, previously the PTN Reactor Vessel Head Alloy 600 Penetration Inspection Program, which manages the aging effect of primary water stress corrosion cracking (PWSCC) for pertinent materials (Alloy 600/82/182) in the reactor coolant pressure boundary. The PTN Unit 3 and 4 reactor vessel heads were replaced in 2004 and 2005 due to the susceptibility of the Alloy 600 penetrations to PWSCC. The replacement reactor heads utilize more PWSCC resistant, Alloy-690 materials on all head penetrations. Visual examination of the Unit 3 and 4 reactor vessel head external surfaces during outages and through the PTN Boric Acid Corrosion AMP are utilized to manage cracking. Future inspections of the reactor vessel heads are in accordance with ASME Code Case N-729-1, which has been included in the PTN-augmented ISI program that includes the conditions listed in 10 CFR 50.55a. PTN will continue to participate in industry programs to ensure that PWSCC is managed for the SPEO. This AMP is used in conjunction with the following PTN AMPs:

- PTN ASME Section XI, Subsections IWB, IWC, and IWD, ISI AMP (Section B.2.3.1).
- PTN Boric Acid Corrosion AMP (Section B.2.3.4).
- PTN Water Chemistry AMP (Section B.2.3.2).

The scope of this AMP includes nickel-alloy components, welds identified in ASME Code Cases N-729 and N-722, as mandated with conditions in 10 CFR 50.55a, and components susceptible to corrosion by boric acid nearby or adjacent to those nickel alloy components. This AMP manages cracking due to PWSCC and loss of material due to boric acid corrosion through the PTN ASME Section XI, Subsections IWB, IWC and IWD, ISI AMP and PTN Boric Acid Corrosion AMP, respectively.

The reactor coolant system leak rate associated with inventory balancing is calculated frequently, as required by PTN TS (Reference B.3.147), Section 4.4.6.2.1.c, and these leak rate calculations can help identify new leaks. Flaw evaluation through 10 CFR 50.55a is used to monitor cracking. Detected flaws are monitored and trended through periodic and successive inspections in accordance with ASME Code Cases N-729 and N-722, as mandated with conditions in 10 CFR 50.55a. The nickel-alloy components within the scope of this AMP are evaluated against the acceptance criteria contained in the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (Section B.2.3.1); boric acid residue or corrosion products are evaluated by the PTN Boric Acid Corrosion AMP (Section B.2.3.4) to determine the leakage source and impact on adjacent and nearby susceptible components.

Components with relevant unacceptable flaw indications are corrected for further services through the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (Section B.2.3.1), which also manages their repair and replacement procedures and activities in accordance with 10 CFR 50.55a and NRC RG 1.147 (Reference B.3.26). Expansion of current inspections and increased inspection frequencies are conducted, as necessary, by the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) for evidence of cracking in susceptible components and by the PTN Boric Acid Corrosion AMP (Section B.2.3.4) for detection of leakage.

The fleet Alloy 600 procedure—based on EPRI MRP-126 (Reference B.3.108)—lists current inspection requirements for nickel-alloy components at PTN.

NUREG-2191 Consistency

The PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, with enhancement, will be consistent with the 10 elements of NUREG-2191, Section XI.M11B, “Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only).”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Update the existing license renewal controls for the plant modification process to ensure that no additional nickel alloys will be used in reactor coolant pressure boundary applications during the SPEO or that, if used, appropriate baseline and subsequent inspections per MRP inspection guidance will be put in place.

Operating Experience

Industry Operating Experience

As summarized in NUREG-2191, industry OE records instances where PSWCC has been observed in (a) PWR vessel head penetrations and (b) bottom-mounted instrument nozzles. Through ongoing efforts of the EPRI Materials Reliability Program, current knowledge regarding aging management for nickel-based alloys and their weld-metal formulations is incorporated into relevant ASME Code Cases applied at PTN.

Site-Specific Operating Experience

The following summary of site-specific OE (which included reviews of corrective actions, audits, NRC inspections, and program health reports) provides examples of how aging effects associated with the PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP are being managed.

1. PTN has been an active participant in WOG, EPRI and NEI initiatives regarding cracking of Alloy-600 reactor vessel head penetrations. The Reactor Vessel Head Alloy 600 Penetration Inspection Program instituted at PTN was a cooperative integrated inspection program created in response to NRC Generic Letter (GL) 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations." This program has proven experience in addressing the concerns and requirements of the GL. In response to NRC Order EA-03-009, PTN performed visual inspections for leakage on the top of the original PTN Units 3 and 4 reactor vessel heads in 2003. No evidence of leakage from penetrations of the Alloy 600 reactor vessel heads was identified. Following replacement of the PTN Unit 3 and Unit 4 reactor vessel closure heads (in 2004 and 2005, respectively), inspections are performed in accordance with ASME Code Case N-729-1. These are augmented examination requirements covered by the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1). Visual and ultrasonic inspections in 2009 and 2014 identified no reportable indications in the replacement closure heads at PTN Units 3 and 4.

2. Inspections for BMI penetrations are performed in accordance with ASME Code Case N-722. These are augmented examination requirements covered by the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1). Visual inspections at PTN Units 3 (in 2009, 2012, and 2015) and 4 (in 2009, 2012 and 2016) identified no reportable indications in the subject penetrations.

3. Following bare metal inspections of the reactor vessel head in 2014, a Boric Acid Evaluation documented boric acid identified on the Unit 4 closure head at one CRDM nozzle and near the head vent line. The 2014 inspections of the Unit 3 closure head also observed boric acid near two core exit thermocouple nozzle assemblies and six CRDM nozzles. In each case, these indications were compared with similar observations that

had been noted in prior outage inspections. It was determined that the leakage occurs during head removal/installation activities. Reviews of collected ultrasonic data confirmed that no flaws exist in any of the subject penetrations. Though there has been no evidence of cracking in the subject penetrations, findings from the inspections outlined above would lead to corrective actions under the PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP prior to loss of component intended function.

4. Program health reports from 2012 through 2017 were reviewed and show a consistent trend of positive program performance for the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) through the global indicators of program personnel, infrastructure, implementation, and equipment. Reviews of program health reports over the same time frame reveal some performance challenges for the PTN Boric Acid Corrosion AMP (Section B.2.3.4) that are being addressed through increased oversight, benchmarking, and prioritizing active leak repairs.

To date, no enhancements to the PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12. This process provides reasonable assurance that the PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP is informed and enhanced, if necessary, by relevant OE.

Conclusion

The PTN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

Program Description

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP is a new condition monitoring program that provides reasonable assurance that reactor coolant pressure boundary CASS components susceptible to thermal aging embrittlement, will continue to perform their intended function consistent with the current licensing basis (CLB) during the SPEO. The American Society of Mechanical Engineers (ASME) Code Class 1 components, including CASS components, are maintained by inspecting and evaluating their condition in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB. The PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) will be supplemented by the new Thermal Aging Embrittlement of CASS AMP which monitors loss of fracture toughness due to thermal embrittlement for ASME Code Class 1 CASS components with service conditions above 250°C (482°F).

The RCS components are inspected in accordance with the ASME Code Section XI. This inspection is supplemented to detect the effects of loss of fracture toughness due to thermal aging embrittlement of CASS piping components except for pump casings and valve bodies. The PTN Thermal Aging Embrittlement of CASS AMP includes determination of the potential significance of thermal aging embrittlement of CASS components based on casting method, molybdenum content, and percent ferrite. For components susceptible to thermal aging embrittlement as defined in NUREG-2191, Section XI.M12, aging management is accomplished through one of the following:

a. Qualified visual inspections, such as enhanced visual examination (EVT-1);

b. Qualified ultrasonic testing (UT) methodology; or

c. Component-specific flaw tolerance evaluation in accordance with the ASME Code Section XI, 2007 Edition and addenda through 2008 (Reference B.3.122).

Additional inspections or evaluations to demonstrate that the material has adequate fracture toughness are not required for components not susceptible to thermal aging embrittlement. Applicable industry standards and guidance documents are used to develop this AMP.

The only CASS components at PTN that are susceptible to thermal aging embrittlement are located in the Reactor Coolant System where the operating temperature is above 250°C (482°F). These components are elbows in RCS piping, RCS system valve bodies, RCS pump casings, and reactor vessel internal components.

For pump casings, as an alternative to the screening for significance of thermal aging embrittlement and other actions described above, no further actions are needed as the original flaw tolerance evaluation performed as part of Code Case N-481 implementation is a time-limited aging analysis (TLAA) and is projected to be applicable for 80 years as described in

Section 4.7.5. For valve bodies, screening for significance of thermal aging embrittlement is not required per NUREG-2191 (Reference B.3.9). The existing PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (Section B.2.3.1) inspection requirements are adequate for RCS valve bodies. Additionally, the reactor vessel internal components that are fabricated from CASS are not within the scope of this AMP, but are managed by the PTN Reactor Vessel Internals AMP (Section B.2.3.7).

The PTN Thermal Aging Embrittlement of CASS AMP will be implemented no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PTN Thermal Aging Embrittlement of CASS AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS).”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

As discussed, this AMP supplements the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1). The PTN Thermal Aging of CASS AMP was developed by using research data (NUREG/CR-4513, Section B.3.11) obtained on both laboratory-aged and service-aged materials. Namely, the PTN AMP is consistent with the NUREG-2191 (Reference B.3.9) XI.M12 AMP, which in turn is based on research data. Outside of this research data, there is no additional industry OE specific to thermal aging embrittlement in CASS components.

Site-Specific Operating Experience

Turning to site-specific OE, the PTN Thermal Aging Embrittlement of CASS AMP is a new program for PTN that is to be implemented no later than 6 months prior to the SPEO. Therefore, there is no existing OE to validate the effectiveness of this AMP at PTN; however, there is OE relevant to RCS CASS components. See Section B.2.3.1 for discussion of the OE associated with the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP for RCS components, including CASS components.

ASME Code Section XI ISI reports from the 2004 Unit 3 RFO and 2006 Unit 4 RFO state that the program examinations of RCS piping have yielded no reportable indications. Note that the ASME Code Section XI ISI inspections are adequate to detect cracking, but not loss of fracture toughness, which will be the responsibility of the PTN Thermal Aging Embrittlement of CASS AMP. The ASME Code Section XI ISI Program health reports during the PEO (2012 to present) show that there have been no identified equipment failures and no implementation issues related to inspections and surveillances under the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program. Therefore, the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is being adequately implemented. Although this OE related to the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is not directly related to the new PTN Thermal Aging Embrittlement of CASS AMP, it demonstrates that CASS components are being appropriately inspected during the PEO.

The leak-before-break (LBB) TLAA for RCS piping (Section 4.7.3) concluded that the RCS piping will perform its component intended functions at EPU conditions for 80 years of service. This TLAA evaluation states that the only significant thermal aging effect on the RCS piping is embrittlement of CASS components. The PTN Thermal Aging Embrittlement of CASS AMP is a new program and therefore will be implemented under EPU conditions during the SPEO.

During the SPEO, OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Implementation of the new PTN Thermal Aging Embrittlement of CASS AMP will effectively manage aging of ASME Code Class 1 components and identify degradation prior to loss of intended function.

Conclusion

The PTN Thermal Aging Embrittlement of CASS AMP will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of this new AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.7 Reactor Vessel Internals

Program Description

The PTN Reactor Vessel Internals (RVI) AMP is an existing condition monitoring AMP. This program is used to manage the effects of age-related degradation mechanisms that are applicable to the PTN RVI components. These aging effects include: (a) cracking, including stress corrosion cracking (SCC), irradiation-assisted stress corrosion cracking (IASCC), and cracking due to fatigue/cyclic loading; (b) loss of material induced by wear; (c) loss of fracture toughness due to thermal aging (TE) and neutron irradiation embrittlement (IE); (d) changes in dimensions due to void swelling (VS) or distortion; and (e) loss of preload due to thermal and irradiation-enhanced stress relaxation and creep.

This AMP is based on the existing PTN RVI AMP, which is consistent with EPRI Technical Report No. 1022863, “Materials Reliability Program: Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines (MRP-227-A),” and is implemented in accordance with NEI 03-08, “Guideline for the Management of Materials Issues.” The staff approved the augmented inspection and evaluation (I&E) criteria for PWR RVI components in NRC Safety Evaluation (SE), Revision 1, on MRP-227 by letter dated December 16, 2011 (Accession No. ML11308A770), and the staff subsequently approved the PTN license renewal RVI program report, which is based on the guidance of MRP-227-A, including all licensee action items.

Because the guidelines of MRP-227-A are based on an analysis of the RVI that considers the operating conditions up to a 60-year operating period, these guidelines are supplemented through a gap analysis that identifies enhancements to the program that are needed to address an 80-year operating period. In this program, the term “MRP-227-A (as supplemented)” is used to describe MRP-227-A as supplemented by the gap analysis performed in Appendix C of this document.

This AMP applies the guidance in MRP-227-A (as supplemented) for inspecting and evaluating RVI components at PTN. These inspections provide reasonable assurance that the effects of age-related degradation mechanisms will be managed during the SPEO. This AMP includes expanding periodic examinations and other inspections, if the extent of the degradation identified exceeds the expected levels. Further inspections are performed in accordance with ASME Code Section XI for PWR removable core support structures in Table IWB-2500-1, Examination Category B-N-3, which are in addition to any inspections that are implemented in accordance with MRP-227-A (as supplemented). Additionally, the PTN Water Chemistry AMP is relied on to mitigate or prevent the effects of corrosive aging mechanisms.

MRP-227-A provides guidance for selecting RVI components for inclusion in the inspection sample. Through this process, the RVIs were assigned to one of the following four groups: “Primary,” “Expansion,” “Existing Programs,” and “No Additional Measures.” Definitions of each group are provided in MRP-227-A.

The result of this four-step sample selection process is a set of “Primary” internals component locations that are inspected because they are expected to show the leading indications of the degradation effects. Another set of “Expansion” internals component locations are specified to expand the sample should the indications be more severe than anticipated.

The degradation effects in a third set of internals locations are deemed to be adequately managed by “Existing Programs,” such as ASME Code Section XI, Examination Category B-N-3, examinations of core support structures. A fourth set of internals locations are deemed to require “No Additional Measures.”

Based on the gap analysis for the 60- to 80-year operating period, one component (fuel alignment pins) is identified as having a greater probability of failure than originally identified, and has been elevated from the “No Additional Measures” inspection category to “Existing Programs.”

Ten components screen in for additional degradation mechanisms compared to the degradation mechanisms identified in the existing PTN RVI AMP. Five new components screen in for fatigue, two components screen in IASCC, and three components screen in for IASCC and IE.

Metal fatigue of the RVI is evaluated for an 80-year operating period at PTN as a TLAA. The results of the analysis in Section 4.3 indicate that the analysis performed for the initial (60-year operating period) license renewal remains bounding, and there are no changes to the CUFs. However, the PTN CUF values used to screen for fatigue in the existing MRP-227-A based license renewal AMP were based on generic, industry representative values. In PTN's recent EPU license amendment request (LAR), several RVI CUF values were identified as applicable to PTN. These values were not PTN-specific, but cited as applicable and taken from an international plant with a similar design. The EPU LAR included CUF values for nine RVI components, which are now subject to AMR. Of these nine components, five PTN RVI components now have CUF values greater than or equal to MRP-227-A screening criterion of 0.1, which were not included in the generic screening of components in MRP-227-A, or the PTN RVI AMP for 40 to 60 years. These components are as follows:

- Lower support columns
- Clevis insert
- Radial keys
- Upper-core plate (UCP) alignment pins
- Upper support plate

Additional accumulation of fluence during the 60- to 80-year operating period causes four components to screen in for additional degradation mechanisms. The total fluence accumulation at the 80-year mark was estimated by Westinghouse and incorporated into the gap analysis. The estimates provided by Westinghouse are generically applicable to Westinghouse designed plants. Comparison of these fluence estimates against the degradation mechanisms with fluence-related threshold values in SLRA Section C.2.2 resulted in five components that screened in for additional degradation mechanisms relative to the 60- to 80-year operating period. These components, and the newly screened-in degradation mechanisms, are as follows:

- Upper support column bases - IASCC
- Upper support column bolting - IASCC, IE
- UCP - IASCC
- Guide tube assembly (GTA) lower flanges - IASCC, IE
- GTA support pins - IASCC, IE

The increase in severity of aging effects is not significant enough to necessitate any changes in the program requirements. While five additional components screened in for fatigue and five additional components screened in for fluence related degradation mechanisms, this only impacted the failure modes, effects, and criticality analysis (FMECA) score for the upper support plate, and did not impact the severity categorization for any components.

The PTN Reactor Vessel Internals AMP relies on PWR water chemistry control to prevent or mitigate aging effects that can be induced by corrosive aging mechanisms. For the management of cracking, the AMP monitors for evidence of surface-breaking linear discontinuities if a visual inspection technique is used as the non-destructive examination (NDE) method or for relevant flaw presentation signals if a volumetric ultrasonic testing (UT) method is used as the NDE method. For the management of loss of material, the AMP monitors for gross or abnormal surface conditions that may be indicative of loss of material occurring in the components. For the management of loss of preload, the AMP monitors for gross surface conditions that may be indicative of loosening in applicable bolted, fastened, keyed, or pinned connections. The AMP does not directly monitor for loss of fracture toughness that is induced by thermal aging or neutron irradiation embrittlement. Instead, the impact of loss of fracture toughness on component integrity is indirectly managed by: (1) using visual or volumetric examination techniques to monitor for cracking in the components, and (2) applying applicable reduced fracture toughness properties in the flaw evaluations, in cases where cracking is detected in the components and is extensive enough to necessitate a supplemental flaw growth or flaw tolerance evaluation. The AMP uses physical measurements to monitor for any dimensional changes due to void swelling or distortion.

The inspection methods are determined in accordance with MRP-228. In all cases, well-established inspection methods are selected. These methods include volumetric UT examination methods for detecting flaws in bolting and various visual (VT-3, VT-1, and EVT-1) examinations for detecting effects ranging from general conditions to detection and sizing of surface-breaking discontinuities. Surface examinations may also be used as an alternative to visual examinations for detection and sizing of surface-breaking discontinuities.

Cracking caused by SCC, IASCC, and fatigue is monitored/inspected by either VT-1 or EVT-1 examination (for internals other than bolting) or by volumetric UT examination (bolting). VT-3 visual methods may be applied for the detection of cracking in non-redundant RVI components only when the flaw tolerance of the component, as evaluated for reduced fracture toughness properties, is known and the component has been shown to be tolerant of easily detected large flaws, even under reduced fracture toughness conditions. VT-3 visual methods are acceptable for the detection of cracking in redundant RVI components (e.g., redundant bolts or pins used to secure a fastened RVI assembly).

In addition, VT-3 examinations are used to monitor/inspect for loss of material induced by wear and for general aging conditions, such as gross distortion caused by VS and irradiation growth, or by gross effects of loss of preload caused by thermal and irradiation-enhanced stress relaxation and creep. In some cases (as defined in MRP-227-A), physical measurements are used as supplemental techniques to manage for the gross effects of wear, loss of preload due to stress relaxation, or for changes in dimensions due to VS or distortion.

Inspection coverages for “Primary” and “Expansion” RVI components are implemented consistent with Sections 3.3.1 and 3.3.2 of the NRC SE, Revision 1, on MRP-227-A, as modified by SLRA Appendix C. Inspection frequencies are consistent with ASME Code Section XI intervals to provide for timely detection, reporting, and implementation of corrective actions for the aging effects and mechanisms managed by the AMP.

Per the initial license renewal AMP, a formal program document for the GTA support pin replacement program does not exist. However, GTA support pins are managed through multiple approaches. While the support pins are not a part of the ASME Code Section XI B-N-3 inspections, the VT-3 inspection of the UCP will provide a partial view of the support pins. These inspections provide a partial view of the split pin heads associated with the peripheral GTAs from the top of the UCP, and the split pin leaves associated with all GTAs from the bottom of the UCP. Additionally, a foreign object search and retrieval (FOSAR) of the reactor vessel is performed every fuel outage, and a visual inspection of the S/G primary channels is performed during outages when eddy current testing of the S/G tubes is performed. Additionally, the PTN GTA support pins were replaced in 2007 and 2008 (Units 3 and 4, respectively) with cold worked 316 SS replacement support pins based on the recommendations from Westinghouse. The design life of the support pins is 40 years, meaning they would operate outside of their design life for five years at the end of the SPEO. The above noted inspections should detect the presence of split pin fragments in the unlikely event that failure does occur.

The AMP applies applicable fracture toughness properties, including reductions for thermal aging or neutron embrittlement, in the flaw evaluations of the components in cases where cracking is detected in a RVI component and is extensive enough to warrant a supplemental flaw growth or flaw tolerance evaluation.

For singly-represented components, the AMP includes criteria to evaluate the aging effects in the inaccessible portions of the components and the resulting impact on the intended function(s) of the components. For redundant components (such as redundant bolts, screws, pins, keys, or fasteners, some of which are accessible to inspection and some of which are not accessible to inspection), the AMP includes criteria to evaluate the aging effects in the population of components that are inaccessible by the applicable inspection technique and the resulting impact on the intended function(s) of the assembly containing the components. The acceptance criteria for inspections fall into one of the following three categories:

- For visual examination (and surface examination as an alternative to visual examination), the examination acceptance criterion is the absence of any of the specific, descriptive relevant conditions; in addition, there are requirements to record and disposition surface breaking indications that are detected and sized for length by VT-1/EVT-1 examinations.

- For volumetric examination, the examination acceptance criterion is the capability for reliable detection of indications in bolting, as demonstrated in the examination Technical Justification; in addition, there are requirements for system-level assessment of bolted or pinned assemblies with unacceptable volumetric (UT) examination indications that exceed specified limits.

- The acceptance criterion for physical measurements on the height of hold-down springs vary with time. The actual hold-down spring height at plant start-up and the required hold-down spring height at the end of 80 years is interpolated linearly to determine the required minimum hold-down spring height.

This AMP follows corrective action procedures consistent with fleet guidance. Any conditions found, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the condition is determined and that corrective action is taken to preclude recurrence. These measures may include engineering evaluations, supplementary examinations, repair, or replacement. Any repair or replacement activities are subject to ASME Code Section XI requirements.

NUREG-2191 Consistency

The PTN Reactor Vessel Internals AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M16A, “PWR Vessel Internals.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN RVI AMP will be enhanced as follows, for alignment with NUREG-2191. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Revise program procedures to incorporate the change in inspection category for the fuel alignment pins identified by the gap analysis.
9. Administrative Controls	Revise program procedures to include the 45-day period to notify the NRC of any deviation from the I&E methodology.

Operating Experience

The Reactor Vessel Internals AMP incorporates industry OE by evaluating component degradation at other sites, and implementing corrective actions when the degradation mechanism is potentially applicable to PTN.

Industry Operating Experience

As identified below, industry operating experience is integral to the PTN Reactor Vessel Internals AMP. Tracking of active degradation mechanisms informs the program on potential issues which are evaluated for potential augmented inspections or material modifications.

Several industry issues have been tracked, evaluated, and incorporated into the PTN reactor vessel internals AMP. Since the implementation of the reactor vessel internals AMP in 2012, four key industry issues have been tracked and dispositioned for relevance to PTN. These include degradation of the baffle bolts, fuel alignment pins, control rod guide tube guide cards, and clevis insert bolting.

Baffle Bolting

Westinghouse released a technical bulletin, TB-12-5 Baffle Bolt Degradation, describing the results of an apparent cause analysis investigating the broken baffle-former bolts observed at D. C. Cook Unit 2 during the fall 2010 refueling outage. The Westinghouse technical bulletin concluded that the bolt failures initiated as a result of irradiation assisted stress corrosion cracking and potential interactions with fatigue. PTN Units 3 and 4 were identified as having similar baffle bolt and internal flow design and the following recommendations were provided:

(1) Monitor ongoing inspection activities for evidence of this bolt failure mechanism. Particular attention should be to objects identified during foreign object search and removal (FOSAR) examinations, fuel damage on peripheral assemblies and cracked or broken bolts identified in UT examinations conducted in accordance with established MRP-227 aging management plans.

(2) All plants should evaluate the information in this bulletin and monitor industry activities related to the inspection and evaluation of baffle-former bolts.

This communication from Westinghouse was documented in the CAP on May 3, 2012, and evaluated to not be an immediate operability concern. PTN FOSAR inspections were credited as being routinely performed, every refueling outage, and have not detected any loose parts that might result from bolt or associated locking bar failures. In addition, fuel inspections and reactor coolant chemistry monitoring had not detected any indications of fuel rod failure due to fretting wear. At this point in time all ISI examinations of baffle former bolts had been satisfactory and there was no history of baffle former bolt failures. The recommended inspection frequencies of MRP-227-A were determined to be acceptable and the program did not require any enhancements.

PTN continued to monitor this issue through active participation in joint industry programs. In October of 2016 MRP-2016-033 issued NEI 03-08, "Needed Interim Guidance Baffle Former Bolts, Industry Issue Update." This update provided immediate guidance relevant to PTN. This was documented in the CAP in October of 2016, along with the plan to address the issue at PTN Units 3 and 4. PTN had previously examined the Unit 3 baffle former bolts in 2015, per the MRP-227-A recommended schedule, with satisfactory results. However, in response to this industry issue, a visual inspection of Unit 3 baffle bolts was scheduled for spring 2017. The Unit 4 UT inspection of baffle former bolts was scheduled for fall 2017, and was not changed. An UT inspection of baffle former bolts remained scheduled for fall 2018 for Unit 3.

The industry baffle former bolt inspection results were continually tracked through participation in the joint industry programs and documented through various ARs. The conclusions remained that the existing inspection schedule was adequate. At the time of the spring 2017 planned visual inspection of Unit 3 baffle bolts, the necessary effective full power years (EFPY) had not been reached, and the inspection was deferred until the fall 2018 UT inspection.

The Unit 4 baffle bolts were inspected in the fall of 2017 using UT. This inspection resulted in 1,052 of 1,088 baffle bolts with satisfactory results, 20 bolts were considered suspect and 16 bolts were not able to be inspected. Westinghouse reviewed the findings and concluded that the as found conditions of the bolting are acceptable for one cycle of operation. Currently, an analysis is being performed which will provide a re-inspection interval for PTN Unit 4 by the end of the current operating cycle.

This operating experience was considered in the reactor vessel internals gap analysis. However, the baffle former bolts are already categorized as a "Primary" component and recognized as having a high failure likelihood. At this point, there are no further steps to be taken to address baffle bolts. Any unsatisfactory inspection results will be addressed through the CAP.

Fuel Alignment Pins

Westinghouse released a technical bulletin, TB-16-4, Fuel Alignment Pin Malcomized Surface Degradation, which identified PTN as being potentially susceptible to surface degradation of the fuel alignment pins, as identified at a plant with a similar configuration. This issue was documented in the CAP, which recognized PTN Units 3 and 4 were susceptible to this degradation mechanism. This potential degradation mechanism was dispositioned as currently having no operability, reportability, or risk significance. This industry operating experience was taken into consideration during preparation of the reactor vessel internals gap analysis of the recommendations in MRP-227-A to extend operations to 80 years. Based on the existence of active degradation of these components at other sites, the failure likelihood of the fuel alignment pins was increased from a ranking of "low" to "high." This change caused the fuel alignment pins to be categorized as an "Existing Program" rather than "No Additional Measures." While the likelihood of failure has become high, the consequences of failure remain low, as documented in MRP-227-A as well as TB-16-4. The existing program relied on for inspection of the fuel alignment pins is the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1), as the fuel alignment pins are inspected on a 10-year interval as a core support component.

Guide Cards

EPRI released industry inspection information that identified higher wear than expected during inspections of the Control Rod Guide Tube guide cards through MRP-2016-035, "Reactor Vessel Internals - Control Rod Guide Tube (CRGT) Guide Cards Emergent Industry Issue Summary." This issue was evaluated to have no impact on the inspections at PTN. Inspections had been performed at both Units 3 and 4 prior to receipt of the industry OE. Unit 3 had satisfactory inspection results and will continue to be inspected consistent with the frequency defined in MRP-227-A. Unit 4 showed signs of degradation which prompted the subsequent inspection to be expanded to 100 percent coverage and within 8.8 EFPY rather than 10 years, consistent with WCAP-17451-P. The wear identified in Unit 4 was determined to not be as extensive as the accelerated wear identified by the industry OE and the subsequent inspection scope and schedule were determined to be sufficient to continue to manage the aging effect. PTN's recognition of these aging effects before the industry OE was available is identified below in the discussion of site-specific operating experience.

Clevis Insert Bolting

EPRI released industry letter MRP-2017-024, Clevis Insert Bolt OE. This letter identified degradation of the clevis insert bolting at Salem Unit 2 during its spring 2017 outage. This issue was documented and evaluated as having no immediate impact to PTN in the CAP. This operating experience was considered in the reactor vessel internals gap analysis based on the evidence of an active degradation mechanism. However, the clevis insert bolts are already categorized as a "Primary" component, and recognized to have a high failure likelihood. At this point, there are no further steps to be taken to address clevis insert bolts. Any unsatisfactory inspection results will be addressed through the CAP.

<u>Site-Specific Operating Experience</u>

Site specific OE is limited, as the program was implemented in 2012. However, prior to implementing the AMP, PTN took action to monitor industry operating experience and implement corrective actions when needed. The original Control Rod Guide Tube (CRGT) support pins were fabricated from X-750 alloy with a heat treatment that was later determined to have rendered them susceptible to stress corrosion cracking based upon external OE. Replacement support pins, also manufactured of X-750 but with a modified heat treatment, were installed in Units 3 and 4 in 1985 and 1986, respectively, per recommendations from Westinghouse. The second generation X-750 support pins were later found to also be susceptible to SCC, again when considering external OE. Based on the recommendations from Westinghouse replacement support pins constructed of cold worked (CW) 316 SS were installed in Units 3 and 4 in 2007 and 2008, respectively. These material modification actions, prior to a formal reactor vessel internals AMP, provide objective evidence that PTN has implemented an effective CAP with respect to reactor vessel internals.

As per the NRC Commitment for the PTN initial License Renewal, the RV Internals must be inspected to meet the criteria noted in EPRI Report, MRP-227-A to manage the aging effects of the RV Internals. The remote visual examination proposed by this program utilizing equipment such as television cameras, fiber-optic scopes, periscopes, etc., has been demonstrated previously as an effective method to detect cracking of reactor vessel internals.

In accordance with the RVI outage inspection plans, all RVI components except guide cards, baffle-former bolts (BFBs) and baffle-edge bolts (BEBs) were inspected during the Unit 3 Spring 2014 refueling outage (RFO). All guide cards and BEBs, and 305 of 1088 BFBs, were inspected during the Unit 3 Fall 2015 RFO. All primary RVI components, except guide cards, GTA lower flange welds, BFBs and BEBs, were inspected during the Unit 4 Fall 2014 RFO. All guide cards and GTA lower-flange welds were inspected during the Unit 4 Spring 2016 RFO. These outage inspections yielded no recordable indications for RVI components. All of the Unit 4 BFBs and BEBs were inspected in the Fall 2017 RFO. The results of this inspection indicate that the bolting conditions are acceptable for one cycle of operation and an analysis is currently being prepared to provide a re-inspection interval. All of the Unit 3 BFBs are scheduled for inspection during the Fall 2018 RFO.

While conducting MRP-227 Guide Card Inspection during the Unit 4 Spring 2016 RFO, ligament wear was noted that exceeds WCAP-17451 allowable value. Evaluation of the condition determined that the guide cards are acceptable for continued service; however, enhanced re-inspection is required. As a consequence of this finding, per WCAP-17451, 100 percent guide card inspection is scheduled to be performed prior to accumulation of another 8.8 EFPY.

The review of site-specific operating experience provides objective evidence that PTN reactor vessel internals inspections are effective in confirming that reactor vessel internals remain in adequate condition to provide component intended function. Additionally, the instances where inspection results were not satisfactory provide evidence that the corrective actions program is effective in addressing material degradation through augmented subsequent inspections and analyses.

Regulatory Audits and Inspections

NRC Inspections

- PTN - NRC Post-Approval Site Inspection for License Renewal Inspection Reports dated July 12, 2012 and December 21, 2012, Accession Nos. ML12195A272 and ML12362A401, respectively (References B.3.58 and B.3.59)

  A post-approval license renewal NRC inspection was performed prior to the initial PEO for Units 3 and 4. No findings were identified as a result of either inspection; however, an observation was identified that the Reactor Vessel Internals Inspection AMP had not been completely developed as described in the latest correspondence submitted to the NRC in December 2011, revising the original license renewal commitment to adopt the guidelines in MRP-227-A. It was determined that, although PTN was on track to meet the commitment within the timeframe requested in the December 2011 letter, this commitment was subject to further NRC inspection during future license renewal inspections to verify that corrective actions have been taken to develop and implement the program in accordance with the revised license renewal commitment.

  During the inspection documented in the December 12, 2012 inspection report, the inspectors determined that there was reasonable assurance that the required program had been established to manage aging effects of the Reactor Vessel Internals to maintain their intended function(s) through the period of extended operation. By letter dated December 18, 2015 the staff issued a safety evaluation report and approved the PTN Units 3 and 4 Reactor Vessel Internals AMP.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN RVI AMP, with enhancements, will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.8 Flow-Accelerated Corrosion

Program Description

The PTN Flow-Accelerated Corrosion AMP is an existing AMP that manages loss of material (wall thinning) caused by flow-accelerated corrosion (FAC). This AMP is based on commitments made in response to NRC GL 89-08 (Reference B.3.34), via FPL letter L-89-265 (Reference B.3.136). This AMP relies on implementation of the EPRI guideline, Nuclear Safety Analysis Center (NSAC)-202L-R3 (Reference B.3.113) for an effective FAC program. This AMP includes the following:

a. Identifying all FAC-susceptible piping systems and components.

b. Developing FAC predictive models to reflect component geometries, materials, and operating parameters.

c. Performing analyses of FAC models and, with consideration of OE, selecting a sample of components for inspections.

d. Inspecting components.

e. Evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections.

f. Incorporating inspection data to refine FAC models. The AMP includes the use of predictive analytical software, such as CHECWORKS™, that uses the implementation guidance of NSAC-202L-R3.

Since the PTN FAC AMP is a condition monitoring program, no preventive actions are taken. With that noted, the rate of FAC or erosion, where applicable, is affected by piping material, geometry and hydrodynamic conditions, and operating conditions such as temperature, pH, steam quality, operating hours, and dissolved oxygen content.

The PTN FAC AMP monitors the effects of wall thinning due to FAC and erosion mechanisms by measuring wall thicknesses. Relevant changes in system operating parameters, (e.g., temperature, flow rate, water chemistry, operating time), which result from off-normal or reduced-power operations, are considered for their effects on the CHECWORKS™ predictive FAC models, and these parameters are included in updates to the CHECWORKS™ predictive FAC models. Opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation. Components are suitable for continued service if calculations determine that the predicted wall thickness at the next scheduled inspection (after next operating cycle) will meet the minimum allowable wall thickness. The minimum allowable wall thickness is the thickness needed to satisfy the component design loads under the original code of construction; additional code requirements are met, as applicable. A conservative safety factor is applied to the predicted wear rate determination to account for uncertainties in the wear rate calculations and UT measurements. The safety factor for acceptable wall thickness and remaining service life is 1.1 or greater, as recommended by NSAC-202L-R3.

The PTN FAC AMP procedures require reevaluation, repair, or replacement of components for which the acceptance criteria are not satisfied, prior to their return to service. For FAC, long-term corrective actions may include replacing components with FAC-resistant materials. Operating parameters that affect predicted FAC wear rates (e.g., operating time, hydrodynamic conditions, water treatment, component material, etc.) may also be adjusted, as long as the corresponding CHECWORKS™ models are also updated. When carbon steel (steel) piping components are replaced with FAC-resistant material, the susceptible components immediately downstream are considered for monitoring to identify any increased wall thinning.

For SLR, the PTN FAC AMP will also manage wall thinning caused by erosion mechanisms in limited situations where periodic monitoring is used in lieu of eliminating the cause, typically a design or operational deficiency, in components that contain treated water (including borated water) or steam. These limited situations are based on site OE and will be monitored similar to other FAC locations that are not modeled.

NUREG-2191 Consistency

The PTN Flow-Accelerated Corrosion AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M17, “Flow-Accelerated Corrosion.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN FAC AMP will be enhanced as follows, for alignment with NUREG-2191. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Include erosion mechanisms such as cavitation, flashing, droplet impingement, or solid particle impingement for the components that contain treated water (including borated water) or steam

Element Affected	Enhancement
3. Parameters Monitored or Inspected 5. Monitoring and Trending	Address erosion as an aging mechanism for components that contain treated water (including borated water) or steam. The following should be included: • Guidelines for measuring wall thickness due to erosion. Wall thickness should be trended to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements. • Evaluations of inspection result to determine if assumptions in the extent-of-condition review remain valid. If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities should consider the number or duration of these occurrences. • Performance of periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed.
4. Detection of Aging Effects	Ensure that identification of susceptible locations of erosion are based on the extent of condition reviews from corrective actions in response to site-specific and industry OE. Components may be treated in a manner similar to “susceptible-not-modeled” lines discussed in NSAC-202L-R3. Additionally, include guidance from EPRI 1011231 (Reference B.3.95) for identifying potential damage locations, and EPRI TR-112657 (Reference B.3.94) and/or NUREG/CR–6031 (Reference B.3.13) guidance for cavitation erosion. Perform a re-assessment of piping systems excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L-R3) to ensure the exclusion remains valid and applicable for operation beyond 60 years. If actual wall thickness information is not available for use in this re-assessment, a representative sampling approach will be used. This re-assessment may result in additional inspections.
7. Corrective Actions	Include long-term corrective actions for erosion mechanisms. The effectiveness of the corrective actions should be verified. Include periodic monitoring activities for any component replaced with an alternative material since no material is completely resistant to erosion.

Operating Experience

Industry Operating Experience

Outage inspection plans for the PTN FAC AMP consider pertinent industry operating experience, such as from NRC Information Notice (IN) 2006-08. Replacements with FAC-resistant materials and inspections have been performed based on OE through evaluation and inspection plan adjustment, both in the industry and at PTN.

External operating experience is evaluated through the AR process to confirm applicability to PTN or identify the appropriate adjustments/improvements to the AMP. For example:

- The evaluation of a 2007 steam leak on a San Onofre steam bypass control valve for PTN applicability confirmed that (a) PTN does not incorporate steam bypass control valves; (b) comparable PTN systems are not used for extended periods as described in the OE; (c) OE of deferring weld repairs have not be found applicable to PTN; and d) no changes to the PTN FAC AMP were necessary.

- A separate 2007 evaluation of OE for Millstone Unit 3 auxiliary feedwater (AFW) pump minimum flow recirculation line wall-thinning determined the PTN configuration to be similar and inspection needed. The PTN restricting orifices and downstream recirculation lines were radiographed and confirmed to be thinning. The sections were replaced with stainless steel sections to enhance corrosion resistance and restore piping thickness. The margin and thinning rates for downstream recirculation lines were also determined and are tracked by the PTN FAC AMP.

Site-Specific Operating Experience

The PTN FAC AMP is a mature, established program. The effectiveness of the PTN FAC AMP, from renewed license issuance in June 2002 to entering the PEO in July of 2012, is described in inspection notebooks compiled in support of the July 2012 NRC post-approval site inspection (Inspection reports 05000250/2012008 and 05000251/2012008, Reference B.3.60) for the original period of extended operation (PEO). This post-approval site inspection identified two observations. The first observation, relative to characterization of examination results, was corrected by requiring identification of external or internal surface indications in the radiographic exam report template. The second observation, regarding the clarification of program scope, was addressed by revising the implementing procedures to explicitly include portions of the auxiliary steam system in the scope of license renewal in the scope of the program.

An integrated NRC inspection of the implementing procedures and program documentation for the erosion-corrosion/flow-accelerated corrosion program, which comprise the PTN FAC AMP, was performed in the 2nd quarter of 2012 (Inspection reports 05000250/2012003 and 05000251/2012003). This focused inspection had no findings and determined that the required actions had been taken to detect adverse effects (wall thinning) on systems and components from operational changes related to the extended power uprate (EPU). The integrated inspection also determined that the program included:

- Systematic methods for predicting which systems were susceptible to erosion-corrosion/FAC.
- The means to inspect those systems, and the methods to analyze and trend inspection results.
- Examination activities performed in accordance with ASME Code requirements.

The PTN FAC AMP is the subject of periodic site/fleet self-assessments and audits. Various recommendations and areas for improvement have been identified through these assessments. For example, a 2009 recommendation for benchmarking a multi-site FAC program was completed as reflected in the current fleet procedure. Other assessments have confirmed that repair/replacement activities were documented in accordance with requirements, and that inspections were performed per CSI procedures using qualified personnel. The time to address self-assessment actions are presently tracked and trended.

Quarterly PTN FAC AMP health reports are also developed and demonstrate that the PTN FAC AMP performance has met expectations since 2012 with some non-CHECWORKSTM software issues that have been resolved and some documentation and database items tracked as long-term strategy items. Final reports are developed for each refueling outage (RFO) that document the inspections, replacements and deferrals for that outage.

The following examples further demonstrate that the PTN FAC AMP remains effective in ensuring that component intended functions are maintained consistent with the CLB:

1. During the Spring 2017 Unit 3 Cycle 29 RFO, the planned large bore and small bore locations were inspected. Planned replacements with FAC-resistant (chromium-molybdenum) materials were also completed. Wall thickness readings were as expected and the next inspections scheduled.

2. During the Spring 2016 Unit 4 Cycle 29 RFO, planned large bore and small bore locations were inspected. Some minor external wall thinning was observed at certain turbine building locations. All three of the locations had wall thicknesses above their respective required minimum thickness values. The locations were identified for future trending and investigation due to the external thinning.

3. During the Fall 2015 Unit 3 Cycle 28 RFO, planned large bore and small bore locations were inspected. The following are an example of the conditions identified and evaluated:

    - Measured wall thicknesses in the Unit 3 heater drain system were identified as less than minimum allowable. The trend for this previously identified thinning was considered. The difference in thicknesses measured since the Unit 3 Spring 2012

RFO 26 and Spring 2014 RFO 27 were determined to be within the accuracy of the measurement equipment. Pipe wall thinning at the T_{min} locations was minimal. Sufficient margin was determined to be available in 2015 and reinspection is scheduled for Unit 3 Cycle 30 RFO in the Fall of 2018.

- A thickness measurement was recorded on a stub in the moisture separator reheater piping. The measured value is the same as minimum allowable value. The condition was entered into the CAP, and the resulting evaluation determined that repairs on this section of piping could not be deferred and appropriate repairs, replacement with FAC-resistant material, were completed prior to startup for Unit 3 Cycle 28 in 2015.

4. A number of components were examined during the Unit 4 Fall 2014 Cycle 28 RFO. Numerous large bore components and small bore components were inspected. All of the small bore components were examined using computed radiography. Inspection results were as expected, with wall thicknesses as predicted. Planned replacements with FAC-resistant material for lines associated with select steam traps was deferred through CAP evaluation. The replacement was scheduled and completed in the Spring 2016 Unit 4 Cycle 29 RFO.

5. Inspections of piping and fittings were performed during the Fall 2012 Unit 4 and Spring 2014 Unit 3 Cycle 27 RFOs. Ultrasonic and radiographic techniques were used as the examination method. For components that fell below the predetermined screening criteria and/or exhibited significant FAC wall thinning, or had a remaining life of less than one operating cycle, the condition was entered into the CAP to determine and perform the final disposition. The Unit 4 inspection activities included five large-bore and five small-bore piping replacements, as well as repairs of one large-bore component and the turbine crossunder piping. The Unit 3 inspection activities included four large-bore and one small-bore component replacements, as well as weld repair of the turbine crossunder piping.

6. The PTN EPRI CHECWORKSTM models were updated in 2011-2012 to anticipate plant wall thinning rates at EPU conditions. The updated models predicted that operation at EPU conditions would result in increased thinning rates in the Unit 3 extraction steam piping leading to the 6th feedwater heater. The piping was replaced with FAC-resistant (chrome moly) material. The equivalent Unit 4 piping had previously been replaced with FAC-resistant material. In addition, the moisture separator reheaters and the 5th and 6th feedwater heaters were replaced with FAC-resistant (chrome moly) material due to EPU.

7. A 2005 condition report addressed a pinhole leak discovered on the recirculating line for a Unit 4 feedwater pump. The leak was evaluated as being due to either FAC, accelerated erosion (cavitation, flashing, or liquid impingement) or an eroded upstream orifice. The upstream orifice was found to be eroded in the last stage, and the eroded orifice caused liquid impingement due to flashing to be directed on a small area of the reducer immediately downstream and result in wall-thinning and pinhole leak. The leak was corrected through weld overlay using appropriate materials without recurrence. Based on evaluation through the CAP, the orifices were scheduled for replacement in subsequent

outages. In the interim between the identification and feedwater pump orifice replacement, the reducers downstream of the steam generator feedwater pumps for both units were included in the flow-accelerated corrosion monitoring program for refueling outages until the long-term solution (stainless steel orifice) had been implemented, which occurred in 2008. As such, the PTN Flow-Accelerated Corrosion AMP is capable of being adjusted to monitor and trend components subject to erosion (cavitation, flashing or liquid impingement) in support of staged or lengthy corrective actions or modifications.

As stated in Section B.1.1, the Auxiliary Feedwater Steam Piping Inspection Program, credited for the PEO, was found to be effective at managing aging in the December 2017 AMP effectiveness review. However, the program had failed elements. This program is not being continued in the SPEO, but the components will be in the scope of the PTN Flow-Accelerated Corrosion AMP during the SPEO. Therefore, the failed elements found for the Auxiliary Feedwater Steam Piping Inspection Program are being included under OE for the Flow-Accelerated Corrosion AMP.

The Auxiliary Feedwater Steam Piping Inspection Program failed Element 7, Corrective Actions, due to an inspection evaluation not adequately predicting degradation rate to drive timely re-inspection or replacement of a component. A subsequent review conducted in December 2017 determined that degradation rate, replacement, and re-inspection for the component were adequately evaluated under the Flow-Accelerated Corrosion AMP, and therefore, found to be acceptable. Program documentation was updated in December of 2017 to link re-inspection and replacement actions between the two programs.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN Flow-Accelerated Corrosion AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.9 Bolting Integrity

Program Description

The PTN Bolting Integrity AMP is an existing AMP related to existing activities, which include the PTN Systems and Structures Monitoring AMP (which previously governed activities to be managed by this AMP during the SPEO) and the PTN ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD AMP (Section B.2.3.1) (which covers safety related bolting). This AMP manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This AMP also manages submerged pressure-retaining bolting and closure bolting for piping systems that contain air or gas for which leakage is difficult to detect.

Applicable industry standards and guidance documents relevant to this AMP include NUREG-1339 (Reference B.3.7), "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," EPRI NP-5769 (Reference B.3.115), "Degradation and Failure of Bolting in Nuclear Power Plants," EPRI Report 1015336 (Reference B.3.98), "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," and EPRI Report 1015337 (Reference B.3.99), "Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints."

The preventive actions associated with this AMP include proper selection of bolting material; the use of appropriate lubricants and sealants in accordance with the guidelines of EPRI Report 1015336 and EPRI Report 1015337, along with additional recommendations from NUREG-1339; consideration of actual yield strength when procuring bolting material (e.g., ensuring any replacement or new pressure-retaining bolting has an actual yield strength of less than 150 ksi); lubricant selection (e.g., not allowing the use of molybdenum disulfide); proper torquing of bolts, checking for uniformity of the gasket compression after assembly; and application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, or engineering evaluation. These actions preclude loss of preload, loss of material, and cracking.

The PTN Bolting Integrity AMP provides inspection of pressure-retaining bolting per ASME Code requirements. Pressure-retaining bolted connections are inspected at least once per refueling cycle as part of ASME Code Section XI leakage tests. For inaccessible components, accessible components with similar materials and environments will be inspected. Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow site procedures that include inspection parameters for items such as lighting and distance offset that provide an adequate examination.

This AMP supplements the inspection activities required by ASME Code Section XI for ASME Code Class 1, 2 and 3 bolting. For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspections (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. Visual inspection methods are effective in detecting the applicable aging effects, and the frequency of inspection is adequate to ensure that actions are taken to prevent significant age-related degradation. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the CAP.

The inspection includes a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) or a maximum of 25 bolts per population at each unit.

Submerged closure bolting that precludes detection of joint leakage is inspected visually for loss of material during maintenance activities. Bolt heads are inspected when made accessible and bolt threads are inspected when joints are disassembled. In each 10-year period during SPEO, a representative sample of bolt heads and threads is inspected. If opportunistic maintenance activities do not provide access to 20 percent of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then the integrity of the bolted joint will be evaluated on a case-by-case basis using methods, such as periodic pump vibration measurements taken and trended or sump pump operator walkdowns performed to demonstrate that the pumps are appropriately maintaining sump levels.

Because leakage is difficult to detect for bolted joints that contain air or gas, the associated closure bolting will be evaluated on a case-by-case basis using one of the following methods:

- Inspections are performed consistent with that of submerged closure bolting.
- A visual inspection for discoloration is conducted (applies when leakage of the environment inside the piping systems would discolor the external surfaces).
- Monitoring and trending of pressure decay is performed when the bolted connection is located within an isolated boundary.
- Soap bubble testing is performed.
- Thermography testing is performed (applies when the temperature of the fluid is higher than ambient conditions).

For component joints that are not normally pressurized, the aging effects associated with closure bolting will be managed by checking the torque to the extent that the closure bolting is not loose.

Indications of aging are evaluated in accordance with Section XI of the ASME Code. Leaking joints do not meet acceptance criteria. When alternative inspections or testing is necessary, site-specific acceptance criteria will be used.

NUREG-2191 Consistency

The PTN Bolting Integrity AMP, with enhancements, will be consistent with the program described in NUREG-2191, Section XI.M18.

Exceptions to NUREG-2191

None.

Enhancements

The PTN Bolting Integrity AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program 4. Detection of Aging Effects	Create a new governing procedure and update existing procedures for this AMP to do the following in accordance with this NUREG-2191 element XI.M18: • Include submerged pressure-retaining bolting in inspections. • Include closure bolting for piping systems that contain air or gas for which leakage is difficult to detect.
2. Preventive Actions	Create a new governing procedure and update existing procedures for this AMP to do the following in accordance with this NUREG-2191 element XI.M18: • Ensure any replacement or new pressure-retaining bolting has an actual yield strength less than 150 ksi. • Ensure that lubricants containing molybdenum disulfide will not be used in conjunction with pressure-retaining bolting.
6. Acceptance Criteria	Include appropriate acceptance criteria for submerged pressure-retaining bolting and closure bolting for piping systems that contain gas or air for which leakage is difficult to detect.

Operating Experience

As described above, the PTN Bolting Integrity AMP is an existing program. During the PEO, the activities it manages were implemented through the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (for safety related bolting) and inspection programs for individual systems previously identified within the scope of the PTN Systems and Structures Monitoring Program.

<u>Industry Operating Experience</u>

NRC Information Notice (IN) 2012-15, issued August 9, 2012, discusses issues related to the use of seal cap enclosures for mitigating leakage from joints that use A-286 bolts. In the two cases examined, bolts of this material were found to be vulnerable to stress corrosion cracking (SCC) as a result of the environment created by leakage into the seal cap. Through the CAP, FPL investigated the applicability of this issue to PTN and found that PTN does not have any seal caps installed.

Per the GALL-SLR, SCC has occurred in high strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). Additionally, operating experience and laboratory examinations show that the use of molybdenum disulfide as a lubricant is a potential contributor to SCC. Based on investigation in response to an NRC request for information supporting license renewal for the current PEO (reported in March 2001), there is currently no high strength bolting within the scope of this program and molybdenum disulfide lubricant is not in use. The existing activities of this AMP will be enhanced to ensure that no new high strength bolting within the scope of this program will be installed and molybdenum disulfide will not be used as a lubricant.

Site-Specific Operating Experience

As discussed above, this program is supplemented by the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. See Section B.2.3.1 for additional discussion of site-specific OE associated with that AMP.

The following summary of site-specific OE (which includes review of corrective actions, NRC inspections, and program health reports) provides examples of how PTN is managing aging effects associated with the PTN Bolting Integrity AMP.

1. In June 2016, Intake Cooling Water (ICW) piping for Unit 4 was found to have a slight water leak coming from the area of a single loose bolt identified during inspection prior to coating activities. There were no visible cracks in the immediate area of the bolt. A corrective action was issued, the flange was tightened, and the leakage stopped.

2. In April 2016, while performing an ASME Section XI examination of the steam generator cold leg manway bolting for Unit 4, damaged threads were observed on the bolt marked #1. A corrective action was issued, the Repair/Replacement program owner was notified, and a replacement bolt was installed.

3. In September 2015, a bolt that holds the top plate to a strainer was discovered by maintenance personnel laying inside the strainer while cleaning it during performance of lubricating oil strainer cleaning for Unit 3. The bolt was reinstalled properly. A corrective action was issued and the model work order (WO) for preventive maintenance on the strainer was updated to ensure that the strainer bolts and washers were properly tightened upon completing maintenance.

4. In December 2014, a small leak under insulation was identified coming from a Unit 4 turbine gland seal. A corrective action was issued to remove the insulation to check the extent of the leak. As a result of the small nature of the leak, the fact that this turbine gland seal is a 10 CFR 54.4(a)(2) component (and thus non-safety related), and the fact that maintenance activities to address this leak required taking the high pressure turbine out of service for approximately 16 hours, the work was not performed until the following

outage. In March of 2016, the insulation was removed, and two out of four strainer bolt nuts were discovered frozen loose. Clamping force on the strainer flange was reduced by half and was leaking past the gasket. Repairs were implemented and no additional corrective actions were deemed necessary. The PTN External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23) is being enhanced to ensure that insulated components and piping are inspected for leakage and moisture inside the insulation. Enhancement to that AMP will help ensure this sort of issue does not go undetected during the SPEO.

5. In June of 2012, the NRC completed a post-approval inspection for license renewal at PTN. The inspectors reviewed licensee actions to address recent industry operating experience and its applicability to a subset of AMPs as described in Revision 2 of the GALL report. Bolting Integrity was one of their selections. The inspectors determined that operating experience was being reviewed for applicability to the existing AMPs. The inspectors noted that some AMPs were revised to adopt the recommendations in the GALL Report or reconcile the gaps with similar programmatic attributes in the existing AMPs. No findings were identified and the inspectors determined that the licensee had completed, or was on track to complete, the necessary tasks to meet the license renewal commitments, license conditions, and regulatory requirements.

6. A review of quarterly program and system health reports issued since Q1 2012 for site programs that implement the PTN Bolting Integrity AMP was conducted to ascertain program performance during the PEO.

    a. Throughout the entire time period reviewed, program health reports for the PTN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) show a consistent trend of positive program performance through the global indicators of program personnel, infrastructure, implementation, and equipment.

    b. The Predictive Maintenance Program and Preventive Maintenance Program health reports were reviewed. They did not identify any history of loss of preload, cracking, or loss of material for bolting within the scope of the PTN Bolting Integrity AMP.

    c. System health reports for select systems (both Units 3 and 4) from representative locations and a variety of environments were reviewed as well, including Containment Spray, Main Steam, and Intake Cooling Water. Reports for Containment Spray and Main Steam reveal no history of loss of preload, cracking, or loss of material for bolting within the scope of the PTN Bolting Integrity AMP. However, reports for Intake Cooling Water revealed several instances of bolting that required replacing. Work orders were issued for those bolt replacement activities and tracked to completion.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new

AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12. While some number of loose or damaged bolts is inevitable, the above OE provides reasonable assurance that the PTN Bolting Integrity AMP will identify and resolve the issues before system function is adversely impacted.

Conclusion

The PTN Bolting Integrity AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.10 Steam Generators

Program Description

The PTN Steam Generator AMP, previously the PTN Steam Generator Integrity Program, is an existing AMP that manages the aging of steam generator tubes, plugs, divider plates, interior surfaces of channel heads, tubesheets (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). The aging of steam generator pressure vessel welds is managed by other AMPs such as the PTN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1), and the PTN Water Chemistry AMP (Section B.2.3.2).

The establishment of a steam generator program for ensuring steam generator tube integrity is required by the PTN TS (Reference B.3.147) Section 3/4.4.5 and Section 6.8.4.j, Administrative control 6.8.4.j, requires tube integrity to be maintained to specific performance criteria, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable tube repair methods, and leakage monitoring requirements. The NDE techniques used to inspect steam generator components covered by this AMP are intended to identify components (e.g., tubes, plugs) with degradation that may need to be removed from service (e.g., tubes), repaired, or replaced, as appropriate.

The PTN Steam Generator AMP is based on the guidelines provided in NEI 97-06, Revision 3, “Steam Generator Program Guidelines.” As such, this AMP incorporates of the following industry guidelines: EPRI-1013706, “PWR Steam Generator Examination Guidelines” (Reference B.3.96); EPRI-1022832, “PWR Primary-to-Secondary Leak Guidelines” (Reference B.3.102); EPRI-1014986, “PWR Primary Water Chemistry Guidelines” (Reference B.3.97; EPRI-1016555, “PWR Secondary Water Chemistry Guidelines” (Reference B.3.100); EPRI-3002007571, “Steam Generator Integrity Assessment Guidelines” (Reference B.3.107); and EPRI-1025132, “Steam Generator In Situ Pressure Test Guidelines” (Reference B.3.103). Through these guidelines, a balance of prevention, mitigation, inspection, evaluation, repair, and leakage monitoring measures are incorporated. Specifically, this AMP incorporates the following from NEI 97-06 (Reference B.3.87):

a. Performance criteria that are intended to provide assurance that tube integrity is being maintained consistent with the CLB.

b. Guidance for monitoring and maintaining the tubes, which provides assurance that the performance criteria are met at all times between scheduled tube inspections.

This AMP will be enhanced to include the latest revisions of the above EPRI guidelines. At this time, only the steam generator examination guidelines need to be updated from Revision 7 to Revision 8 for the current PEO. Maintaining the latest revisions of these EPRI guidelines is a part of the existing AMP, as such this is a commitment of the existing AMP. Revision 8 became available in August of 2017 and implementation is currently underway.

Since degradation of divider plate assemblies, channel heads (internal surfaces), or tubesheets (primary side) may have safety implications, the PTN Steam Generators AMP addresses degradation associated with steam generator tubes, plugs, divider plates, interior surfaces of channel heads, tubesheets (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). This AMP does not include in its scope the steam generator secondary side shell, any nozzles attached to the secondary side shell or steam generator head, or the welds associated with these components. In addition, the scope of this AMP does not include steam generator primary side chamber welds (other than general corrosion of these welds caused as a result of degradation (defects/flaws) in the primary side cladding).

In April 2012 PTN submitted an application to amend the Steam Generator Program as well as Technical Specification 6.9.1.8, "Steam Generator Tube Inspection Report." This application provided a technical justification to establish a permanent steam generator tube alternate repair criteria (H*) for tubing flaws located in the lower region of the tubesheet and accompanying inspection and reporting requirements. This application was reviewed and approved by the staff by letter dated November 5, 2012 (Reference B.3.139). This alternate repair criteria removes the tube-to-tubesheet weld from the credited pressure boundary and removes the inspection criteria for the portion of the tube below 18.11 inches from the top of the tubesheet.

The PTN Steam Generator AMP includes preventive and mitigative actions for addressing degradation. This includes foreign material exclusion as a means to inhibit wear degradation and secondary side maintenance/cleaning activities, such as sludge lancing, for removing deposits that may contribute to degradation. Primary side preventive maintenance activities include replacing corrosion susceptible plugs with corrosion resistant materials and preventively plugging tubes susceptible to degradation. Additionally, this AMP works in conjunction with the PTN Water Chemistry AMP (Section B.2.3.2), which monitors and maintains water chemistry to reduce susceptibility to SCC or IGSCC.

The procedures associated with this AMP provide parameters to be monitored or inspected except for steam generator divider plates, channel heads, and tubesheets. For these latter components, visual inspections are performed at least every 72 effective full power months or every third RFO, whichever results in more frequent inspections. These inspections of the steam generator head interior surfaces, including the divider plate, are intended to identify signs that cracking or loss of material may be occurring (e.g., through identification of rust stains).

Inspections of the divider plate may be required for the SPEO. Nickel-alloy divider plates could experience PWSCC as described in the SRP-SLR (Reference B.3.10). The analysis performed by the industry (EPRI TR 3002002850 (Reference B.3.104)) is applicable as PTN has an alloy-600 divider plate. The industry analyses are currently being evaluated to determine whether it is bounding for PTN and will be completed prior to the SPEO. If the evaluation is not bounding, PTN will perform a one-time inspection of the divider plates to confirm the effectiveness of the actions currently in place to manage SCC (Water Chemistry AMP and the visual inspections performed for the existing Steam Generator AMP).

The goal of the inspections associated with this AMP is to ensure that the in-scope components continue to function consistent with the design and CLB of the facility (including regulatory safety margins). These inspections, based on the PTN TS (Reference B.3.147), are performance-based, and the actual scope of the inspection and the expansion of sample inspections are justified based on the results of the inspections. If degradation or evidence of degradation is detected, then more detailed inspections are to be performed. The AMP procedures reflect these requirements and outline the inspection program to detect degradation of tubes, plugs, and secondary side internals and provide the inspection frequencies. The inspections and monitoring are performed by qualified personnel using qualified techniques in accordance with approved licensee procedures. The PTN primary-to-secondary leakage monitoring program also provides a potential indicator of a loss of steam generator tube integrity.

Condition monitoring assessments are performed to determine whether the structural- and accident-induced leakage performance criteria were satisfied during the prior operating interval. Operational assessments are performed to verify that structural and leakage integrity will be maintained for the planned operating interval before the next inspection. If tube integrity cannot be maintained for the planned operating interval before the next inspection, corrective actions are taken in accordance with the PTN CAP. Comparisons of the results of the condition monitoring assessment to the predictions of the previous operational assessment are performed to evaluate the adequacy of the previous operational assessment methodology. If the operational assessment was not conservative in terms of the number and/or severity of the condition, corrective actions are taken in accordance with the PTN CAP. Assessment of tube integrity and plugging or repair criteria of flawed tubes is in accordance with the PTN TS (Reference B.3.147). The criteria for plugging or repairing steam generator tubes are based on NRC RG 1.121 (Reference B.3.23) and are incorporated into the PTN TS.

Degraded plugs, divider plates, channel heads (interior surfaces), tubesheets (primary side), and secondary side internals are evaluated for continued acceptability on a case-by-case basis. The intent of all evaluations is to ensure that the components will continue to perform their functions consistent with the design and licensing basis of the facility, and will not affect the integrity of other components (e.g., by generating loose parts). In addition, when degradation of the steam generator tubes is identified, the TS specified actions are followed. For degradation of other components, the appropriate corrective action is evaluated per NEI 97-06 and the associated EPRI guidelines, the ASME Code Section XI, 10 CFR 50.65, and 10 CFR Part 50, Appendix B, as appropriate.

NUREG-2191 Consistency

The PTN Steam Generators AMP, with exception and enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M19, “Steam Generators.”

Exceptions to NUREG-2191

The tube-to-tubesheet welds of the PTN steam generators are exempt from inspection and monitoring per the NRC safety evaluation report for permanent Alternate Repair Criteria (H*) for steam generator tubes (Reference B.3.139).

Enhancements

The PTN Steam Generators AMP will be enhanced as follows for alignment with NUREG-2191. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	A new inspection may be required to be implemented for SLR. An evaluation of EPRI TR-3002002850 (Reference B.3.104) is scheduled to be completed by the end of 2018 as part of the existing steam generator AMP for the current PEO to determine if the PTN divider plate is bounded by the analysis. If the analysis is not bounding, a one-time inspection must be scheduled no later than six months prior to entering the SPEO, and must be performed prior to entering the SPEO. Update AMP procedures to include adding reference lists, which include EPRI documents, and including additional means for monitoring loose parts.

Operating Experience

Industry Operating Experience

NEI 97-06 provides guidance to the industry for routinely sharing pertinent steam generator OE and for incorporating lessons learned from plant operation into guidelines referenced in NEI 97-06. The latter includes providing interim guidance to the industry, when needed.

Steam generator tubes have experienced outside diameter stress corrosion cracking, intergranular attack, wastage, and pitting (NRC IN 97-88). Carbon steel support plates in steam generators have experienced general corrosion. Steam generator shells have experienced pitting and SCC (NRC INs 82-37, 85-65, and 90-04).

Operating experience from international Westinghouse steam generators showed primary water stress corrosion cracking in the divider plate assembly of the channel head. EPRI released an analyses to disposition these degradation events in the report, "Steam Generator Management Program: Investigation of Crack Initiation and Propagation in the Steam Generator Channel Head Assembly" and found that the risk of crack initiation and propagation are low enough to not warrant enhanced inspections for further actions. Subsequent analysis performed by PTN determined that the operating experience was applicable to both Units 3 and 4. The EPRI analyses are currently being evaluated to determine if the results are bounding for PTN; this evaluation is anticipated to be complete in early 2018. Enhancements to the program are identified in the event that the results of the EPRI analyses are found to not be bounding for PTN.

In October 2015, EPRI issued a Part 21 letter describing a change to the calibration of several eddy current technique specification sheets (ETSSs). The applicable revised ETSSs were evaluated for their impact to prior inspections at PTN, and only four tubes in PTN Unit 3 remain in service based on affected ETSS sizing. These four tubes were reevaluated against the updated condition monitoring degradation limit, and remain well within condition monitoring degradation limits.

The recent industry occurrences of SCC in Alloy 600 thermally treated (TT) tubing are relevant to PTN, as the replacement steam generator design uses A600TT tubes. SCC has been observed at top-of-tubesheet (TTS) (Vogtle, Surry, Catawba), below TTS (Wolf Creek), and in freespans and tube support plates (TSPs) (Seabrook, Braidwood, Catawba). SCC is considered a potential degradation mechanism at PTN and the inspection plan has been written to address this.

Industry operating experience is monitored on a continuous basis to ensure the AMP's examination scope will address all known degradation conditions. Operating experience regarding corrosion type degradation is relevant to PTN, but the examination plans for PTN Units 3 and 4 address applicable operating experiences regarding wear degradation and are therefore current to the latest service information.

<u>Site-Specific Operating Experience</u>

The current steam generator inspection activities have been evaluated against industry recommendations provided by EPRI and Westinghouse. In addition, the overall effectiveness of the program is supported by the excellent steam generator OE and favorable inspection results.

The Steam Generator Integrity Program considers the guidance provided in NEI 97-06, which has undergone extensive industry and NRC review. This program is all-inclusive in managing steam generator tube bundle and internals degradation. The Steam Generator Integrity Program has been reviewed by the NRC during several inspections and no deviations or violations have been identified. Quality Assurance surveillances and reviews have been performed with no deficiencies identified.

The PTN replacement steam generators have operated for twenty cycles. At end of cycle (EOC) 28 (March 2017), the cumulative operating time for PTN Unit 3 is approximately 27.43 EFPY. At EOC 28 (March 2016), the cumulative operating time for PTN Unit 4 is approximately 25.80 EFPY. The only existing aging degradation is wear at tube support structures. There has been no corrosion degradation observed.

In April 2012 PTN submitted an application to amend the Steam Generator Program as well as Technical Specification 6.9.1.8, "Steam Generator Tube Inspection Report." This application provided a technical justification to establish a permanent steam generator tube alternate repair criteria (H*) for tubing flaws located in the lower region of the tubesheet and accompanying inspection and reporting requirements. This application was reviewed and approved by the staff by letter dated November 5, 2012 (Reference B.3.139). This alternate repair criteria removes the tube-to-tubesheet weld from the credited pressure boundary and removes the inspection criteria for the portion of the tube below 18.11 inches from the top of the tubesheet.

The first post-EPU tube examination at PTN Unit 3 showed a minor increase in anti-vibration bar (AVB) wear. Other types of wear (tube support plate (TSP) wear, flow distribution baffle (FDB) wear) had too few indications to clearly demonstrate a trend. In all cases, the existing 95 percent bounding wear rates for each mechanism continued to bound the observed post-EPU wear rates, and EPU was judged to have affected wear negligibly. The inspection scope for PTN continues to monitor mechanical wear and any effects of EPU on wear rates will be noted.

PTN is limited to 5 percent tube-plugging margin. There are a total of 190 tubes (48 (1.49 percent) in steam generator 3A, 80 (2.49 percent) in steam generator 3B, and 62 (1.93 percent) in steam generator 3C) that were plugged in PTN Unit 3 steam generators as of December 2016. There are a total of 67 tubes (33 (1.03 percent) in steam generator 4A, 23 (0.72 percent) in steam generator 4B, and 11 (0.34 percent) in steam generator 4C) that were plugged in PTN Unit 4 steam generators as of EOC 28 (March 2016). The reason tubes have been plugged and removed from service is tracked. Many of the tubes removed from service were plugged as a result of the pre-service inspection or as a result of in-service wear at the intersections with anti-vibration bars (AVB).

The PTN steam generator inspections have been performed at the frequency defined in TS 6.8.4.j.d.2 since installation. The current steam generators were installed in 1982 and 1983 for Units 3 and 4 respectively. The frequency of inspections per TS are every 48 effective full power months, or at least every other refueling outage (whichever results in more frequent inspections. The coverage for the inspections is defined as follows:

a. After the first refueling outage following SG installation, inspect 100 percent of the tubes during the next 120 effective full power months. This constitutes the first inspection period.

a. During the next 96 effective full power months, inspect 100 percent of the tubes. This constitutes the second inspection period.

a. During the remaining life of the steam generators, inspect 100 percent of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

All steam generators have completed the requirements of a and b, and 100 percent of the tubes are currently being inspected every 72 effective full power months. The latest degradation assessment for both units was issued in December of 2016, which outlines the degradation history and current condition of the steam generators. There is currently active wear degradation in three locations in Unit 3. The anti-vibration bars, support plates, and flow distribution baffle all have active wear, initially identified in 1990, 1985, and 2007 respectively. Unit 4 is experiencing the same active wear in the same locations, initially identified in 1993, 2003, and 2000 respectively. These wear mechanisms are tracked and addressed through operational assessments.

Bobbin and rotating coil eddy current inspections, along with visual inspections during sludge lancing and foreign object search and retrieval are used to detect foreign objects. Foreign objects are removed if possible, however there are instances where removal has not been feasible. For cases where foreign objects are not removed, engineering evaluations are performed to document the safety significance and updated after each inspection. Foreign objects in the steam generators contributes to wear of tubes, however, it is not considered an active degradation mechanism and is treated on a case-by-case basis. To date, twelve tubes have been plugged in Unit 3 and nine tubes have been plugged in Unit 4 as a result of wear cause by foreign objects or suspected foreign objects. Tube plugging due to foreign objects has not been required at Unit 3 since 2001, or at Unit 4 since 2006.

Since the December 2016 degradation assessment, the Unit 3 steam generators have been inspected, in March of 2017. The results of the steam generator inspections are documented in AIM 161210184-2Q-3, Condition Monitoring and Operational Assessment for the PTN Unit 3 Steam Generators Based on Eddy Current Examination End of Cycle 28, March 2017 and are summarized as follows:

The EOC 28 (March 2017) steam generator examination identified anti-vibration bar wear, wear at broached tube support plates, wear at flow baffle plates, and foreign object wear in the PTN Unit 3 tubing. There was no evidence of any tube degradation related to corrosion mechanisms within the defined pressure boundary.

Six tubes were removed from service during EOC 28 (March 2017) outage by plugging. Five of the six tubes had detected wear. The sixth tube was preventively plugged due to a historical geometric obstruction.

Secondary-side inspection of the tube bundle did not reveal any abnormalities. Foreign objects remaining in the bundle were identified and evaluated. Foreign objects remaining in the steam generators will be tracked at future inspections. Primary-side visual inspection of installed tube plugs and channel-head bowl showed no abnormalities were present.

Deterministic condition monitoring demonstrated that the as-inspected condition of the steam generators met the structural and leakage performance criteria contained in NEI 97-06. All indications met the structural requirements for burst with conservative ECT error assumptions. All detected tube indications were smaller than the CM Structural Limits for burst and therefore posed no challenges to tube structural integrity. Cumulative leakage at accident conditions for potential leakage within the tubesheet, was determined to be negligible as contrasted to the accident-induced leakage acceptance criteria.

The results of the operational assessment support full cycle operation for the current Cycle 29. Further, operation for two cycles between inspections is supported by this assessment. The projected leak rates associated with the observed wear degradation were determined to be negligible. No administrative operational limits are required for the next inspection interval. Therefore, the tube integrity requirements of NEI 97-06 will be met for the planned PTN Unit 3 operational schedule for two cycles until the next tube inspection in March 2020.

The results of this inspection were documented in the CAP.

Program Assessments and Evaluations

The results of the program QA audits demonstrate that PTN is effective in implementing the Steam Generators AMP.

In 2003, oversight of the activities related to chemistry controls during shutdown, startup and cleaning and inspection of the Steam Generators was performed during the Unit 4 Cycle 21 Refueling Outage. With respect to cleaning and inspection of the Steam Generators, the results indicated the work activities associated with the secondary side of the steam generator went well. A review of work control documents contained in QA records and observations conducted during the outage identified proper use of work control processes to complete the assigned activities.

In 2003, 2004 and 2008, audits were conducted of the Chemistry and Effluents Functional Area, all of which included the Steam Generator Integrity Program (SGIP) as part of the audit scope. The audits concluded that the implementation of the program is effective at minimizing tube defects as evidenced by the low number of tubes that required plugging and that the tubes plugged to date have been preventive. In addition, relatively small quantities of sludge have been removed from the secondary side of the steam generators even though more advanced removal techniques have been utilized. This is coincident with the implementation of a mixed amine chemistry control scheme for the secondary side, which is credited for reducing iron transport to the steam generators.

Regulatory Audits and Inspections

These examples demonstrate that the program's inspections, examinations, and tests are performed utilizing the PTN TS and appropriate industry codes and guidance documents.

- NRC Integrated Inspection Reports for 4Q 2010, 4Q 2012 and 2Q 2014, Accession No. ML110280004, ML13030A208 and ML14212A253, respectively

  The inspectors observed multiple Steam Generator tube inspection activities and/or reviewed documentation and evaluated them against Technical Specifications, commitments made to the NRC, ASME Section XI, and the NEI 97-06 Steam Generator Program guidelines.

  No findings were identified.

- NRC Integrated Inspection Report (2Q 2011), Accession No. ML112082835

  For the Unit 4 steam generators, no eddy current testing was required pursuant to the TSs during this refueling outage. However, the inspectors evaluated the review of the Degradation Assessment from the previous outage to ensure that it supported a skip cycle for the Unit 4 steam generators.

  No findings were identified.

- PTN – NRC Integrated Inspection Report 4Q 2015, April 6, 2016, Accession No. ML16095A172

  The inspectors verified that for the U3 steam generator tubes, no inspection activities were required for this RFO, in accordance with the requirements of the ASME Code, the licensee's TS, and Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines."

  No findings were identified.

- NRC Integrated Inspection Reports 2Q 2016 and 2Q 2017, Accession No. ML16225A526 and ML17223A012, respectively

  The inspectors reviewed the eddy current examination activities performed in selected steam generators to verify compliance with the licensee's TS, ASME BPVC Section XI, and NEI 97-06, "Steam Generator Program Guidelines." The inspectors reviewed the scope of the EC examinations, and the implementation of scope expansion criteria, to verify these were consistent with the EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 7. The inspectors reviewed documentation for a sample of EC data analysts, probes, and testers to verify that personnel and equipment were qualified to detect the applicable degradation mechanisms in accordance with the EPRI Examination Guidelines.

  As part of the 2Q 2016 inspection, the inspector selected a sample of degradation mechanisms from the Unit 4 Degradation Assessment report and verified that their respective in-situ pressure testing criteria were determined in accordance with the EPRI "Steam Generator Integrity Assessment Guidelines," Revision 3. The inspectors' review also included the implementation of tube repair criteria and repair methods to verify they were consistent with plant Technical Specifications and industry guidelines.

  As part of the 2Q 2017 inspection, the inspectors reviewed the last Condition Monitoring and Operational Assessment report to assess the prediction capability for maximum tube degradation. The inspectors' review also included the licensee's repair criteria and repair process to ensure that they were consistent with plant Technical Specifications and industry guidelines. The inspectors also reviewed the primary-to-secondary leakage (e.g., SG tube leakage) history for the last operating cycle. The inspectors noted that primary-to secondary leakage was below the detection threshold during the previous operating cycle; none had been detected.

No findings were identified during these inspections.

Program Health Reports

Program health reports are issued quarterly for the steam generators. Dating back to 2012, with one exception, all program health reports have reported favorable program health, with a GREEN rating. The first quarter of 2013 had a rating of WHITE and was recovered to a GREEN rating by the second quarter of 2013. Overall, program health reports have demonstrated effective performance of the Steam Generators AMP.

The implementation of this AMP, through the guidelines of the NEI 97-06 program has been effective at managing the aging effects associated with steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals), such that the steam generators can perform their intended safety function.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Steam Generators AMP, with exception and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.11 Open-Cycle Cooling Water System

Program Description

The PTN Open-Cycle Cooling Water (OCCW) System AMP, previously the PTN Intake Cooling Water (ICW) Inspection Program, is an existing AMP that, in part, implements the PTN response to the recommendations of NRC GL 89-13 (Reference B.3.35), "Service Water System Problems Affecting Safety-Related Components," to provide reasonable assurance that the effects of aging on the OCCW system (or ICW system at PTN) will be managed for the SPEO. NRC GL 89-13 defines the OCCW system as a system or systems that transfer heat from safety-related SSCs to the ultimate heat sink (UHS). This AMP is comprised of the aging management aspects of the PTN response to NRC GL 89-13, including:

a. A program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling.

b. A program to verify heat transfer capabilities of all safety-related heat exchangers cooled by the OCCW system.

c. A program for routine inspection and maintenance to provide reasonable assurance that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of safety-related systems serviced by the OCCW system.

Since the guidance in NRC GL 89-13 was not specifically developed to address aging management, this AMP includes enhancements to the guidance in NRC GL 89-13 that address OE to provide reasonable assurance that aging effects are adequately managed during the SPEO. The PTN OCCW System AMP manages aging effects of components in raw water systems, such as the PTN ICW system, by using a combination of preventive, condition monitoring, and performance monitoring activities. These activities include:

a. Surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, and fouling in the OCCW SSCs serviced by the OCCW system.

b. Inspection of components for signs of loss of material, corrosion, erosion, cracking, fouling, and biofouling.

c. Testing of the heat transfer capability of heat exchangers that remove heat from components important to safety.

The PTN OCCW AMP works in conjunction with other PTN AMPs as described in this paragraph. For buried OCCW system piping within the scope of this AMP, the aging effects on the external surfaces of the piping are managed by the PTN Buried and Underground Piping and Tanks AMP; however, the internal surfaces are managed by this AMP. The aging management of closed-cycle cooling water systems is described in the PTN Closed Treated Water Systems AMP and is not included as part of this AMP. The PTN OCCW System AMP also manages the loss of coating integrity for internal coatings of piping within the scope of this AMP. This piping includes cement-lined cast iron piping from the three (3) ICW pump discharge check valves to the component cooling water (CCW) basket strainers and piping from the three (3) ICW pump discharge check valves to the turbine plant cooling water (TPCW) baskets strainers.This AMP includes the guidance provided in the "scope of program" elements of the PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP to manage loss of coating integrity.

NUREG-2191 Consistency

The PTN Open-Cycle Cooling Water System AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M20, "Open-Cycle Cooling Water System."

Exceptions to NUREG-2191

None.

Enhancements

The PTN Open-Cycle Cooling Water System AMP requires the following enhancements to be consistent with NUREG-2191, Section XI.M20. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	The specific aging mechanism associated with coatings/linings (blistering, cracking, flaking, peeling, delamination, and rusting) and descriptions shall be delineated in the pertinent testing specification SPEC-M-086.
4. Detection of Aging Effects	The inspection interval for ICW piping internal inspections, as delineated in the pertinent testing specification SPEC-M-086, should not exceed five years. In addition, changes to piping internal inspection intervals are to be established by a coating specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54 (Reference B.3.20). For cementitious ICW piping coatings within the scope of the program, 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.

Element Affected	Enhancement
6. Acceptance Criteria	Coating acceptance criteria specific in the pertinent testing specification SPEC-M-086 shall meet the acceptance criteria of element 6 of NUREG-2191 Section XI.M42, which are as follows: a. There are no indications of peeling or delamination. b. Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size or frequency should not be increasing between inspections (e.g., ASTM D714-02 (Reference B.3.129), "Standard Test Method for Evaluating Degree of Blistering of Paints"). c. Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 (Reference B.3.20) including staff limitations associated with use of a particular standard. d. Minor cracking and spalling of cementitious coatings/ linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material. e. As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. f. Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in site-specific design requirements specific to the coating/lining and substrate. g. In addition, evaluation of coating deficiencies shall be performed by individuals that meet the qualification requirements of element 6 of NUREG-2191 Section XI.M42.

Operating Experience

Industry Operating Experience

1. The existing ICW Inspection Program has been an ongoing formalized inspection program at PTN. The program was formally implemented as a result of NRC Generic Letter GL 89-13, which recommended monitoring of service water systems to ensure that they would perform their safety-related function based on OE of biological fouling and corrosion throughout the industry. The conservative philosophy established within the program has been successful in managing the loss of material due to corrosion and

fouling of the CCW heat exchangers. This program has been effective in maintaining acceptable CCW heat exchanger performance and addressing biological fouling of strainers and heat exchangers. Various sections of the ICW piping, basket strainers, and heat exchangers are periodically examined using NDE to determine the effects of corrosion and biological fouling. Results are evaluated and components are either repaired or replaced, as required.

Site-Specific Operating Experience

The following review of site-specific operating experience prior to and during the first PEO provides objective evidence that the Open-Cycle Cooling Water (OCCW) System AMP effectively manages aging effects so that the intended functions of SCs within the scope of the OCCW AMP will be maintained during the SPEO.

1. The internal surfaces of portions of the Unit 4 ICW system were inspected during the Spring 2016 refueling outage. The inspected piping included the B ICW header, B ICW pump discharge piping, and C ICW pump discharge piping. The crawl-through inspection concluded the piping inspected was generally in good condition with only 15 locations requiring minor coating repair. Eleven of the 15 coating defects were repaired. Four coating defects, located at the top of the B ICW pump discharge riser, could not be directly inspected or repaired due to the height of the defects and access restrictions. Repair of these four coating defects will be completed concurrent with the replacement of the 4B ICW pump discharge check valve currently scheduled for August of 2018.

2. In June of 2017, eddy current examination (ECT) was performed on 100 percent (1625) of the tubes in the 3B CCW heat exchanger. This was the first inspection of this heat exchanger since it was retubed in February of 2015. (Note that baseline ECT was not performed after the retubing effort). The inspection was performed as part of as general assessment of balance-of-plant (BOP) heat exchangers at the site. Aluminum brass CCW heat exchanger tubing at PTN has had a history of inside diameter pitting corrosion due to the salt water environment.

   Pitting was observed in virtually all the tubes. Thirteen tubes had greater than 70 percent wall loss and were plugged. A total of 310 tubes had wall loss greater than 50 percent. Corrosion rates for the pitting indications could not be quantified as this was the first ECT for this heat exchanger tubing. This premature tube degradation was entered into the CAP and an Apparent Cause Evaluation (ACE) was performed. To support the ACE, selected tubes with indications were removed from the heat exchanger. These tubes and two unused tubes were sent to an offsite laboratory for metallurgical analysis. One of the unused tubes was sectioned before shipment to the offsite lab. The technician observed a "pre-existing cleanliness issue" and the presence of a black, unidentified substance that was adhered to the inner tube wall. The offsite laboratory also identified the black deposits that exhibited high amount of elemental sulfur potentially indicative of attack by microbes. The ACE concluded that the initial tube condition, prior to installation in the CCW heat exchanger, was inadequately cleaned by the manufacturer, creating localized corrosion pitting sites. A contributing cause was the fact that the tube did not receive a baseline ECT after installation, resulting in a missed opportunity to detect pre-existing flaws within the tubes.

Corrective actions included a partial retubing of the 3B CCW heat exchanger in August of 2017 to gain additional operating margin. Additional corrective actions from this event are being evaluated and will be identified in 2018.

3. While performing the annual preventive maintenance (PM) activities on the 3A ICW/CCW basket strainer in 2016, several deficiencies were found. All five strainer screen mounting bars were found lying on the bottom of the strainer, cap screw heads were significantly worn, and the four zinc anodes, used to slow down corrosion rates of the basket strainer, were missing. (Note that this strainer was replaced in its entirety in 2010 due to material condition issues). This issue was entered into the CAP for evaluation. Investigation and discussion with an industry peer revealed that the addition of copper sulfate into the cooling canal system to remediate high algae concentrations in mid-2014 was a contributing factor in accelerated corrosion of the zinc anode wear being observed in the Unit 3 and 4 ICW basket strainers. In addition, increasing salinity levels in the cooling canal system were contributing to the accelerated corrosion of the mounting bar cap screws. Note that the cooling canal copper concentration returned to normal levels by the end of 2014 and on-going salinity remediation efforts continue to lower the cooling canal salinity level and these actions reduce the corrosion potential of susceptible materials.

   Corrective actions included a design change to replace the low alloy steel cap screws with stainless steel cap screws. The cap screw corrosion will continue to be monitored during the annual strainer PM activities.

4. ICW pump inspections are performed every 18 to 22 months. The materials and internals of the discharge check valves have been changed to extend the frequency of the inspections to 42 months. The internal piping is inspected every four outages. The discharge piping and flanges were recently coated externally. The buried piping has a concrete liner that is inspected using crawl through visual inspections.

5. The ICW system has been the subject of several NRC inspections over time. The following inspection items are of note:

   The NRC completed Integrated Inspection Reports for 2Q 2012, 1Q 2013, 3Q 2014, 1Q 2015, 1Q 2016, 3Q 2016, 4Q 2016 and 1Q 2017, as documented in Accession Nos. ML12213A232, ML13115A425, ML14296A129, ML15121A674, ML16124A272, ML16315A226, ML17025A006 and ML17131A318, respectively.

   During the 2Q 2012 and 3Q 2014 inspections, the inspectors verified heat exchanger performance monitoring for selected safety-related heat exchangers. The inspectors checked that monitoring and trending of heat exchanger performance was done at an appropriate interval and that the licensee routinely verified the operational readiness of the system should it be needed for accident mitigation. The inspectors verified that the heat transfer method described in EPRI-NP-7552, Heat Exchanger Performance Monitoring Guidelines, was employed. The inspectors walked down portions of the cooling systems for integrity checks and to assess operational lineup and material condition. On a routine frequency, the inspectors monitored maintenance activities associated with heat exchanger cleaning and biofouling prevention. The inspectors also conducted field observations of testing required by the PTN Technical Specifications and component replacement/upgrade activities. No findings were identified as a result of these inspections.

During the 1Q 2013, 1Q 2015, 1Q 2016, 3Q 2016 and 1Q 2017 inspections, the inspectors selected various CCW heat exchangers to verify that non-routine maintenance and performance test inspections were being performed in accordance with required surveillance procedures. The inspectors observed portions of the heat exchanger surveillance data collection and reviewed the applicable data sheets for completeness. The inspectors reviewed completed CCW heat exchanger procedure performance tests to ensure the heat exchanger was tested satisfactorily with no deficiencies. The inspectors walked down portions of the CCW cooling system for integrity checks and to assess operational lineup and material condition of the heat exchangers, pumps, motors, and associated valves and piping. No findings were identified as a result of these inspections.

The 1Q 2013 and 4Q 2016 inspections were triennial inspections during which the inspectors interviewed plant personnel and reviewed records for a sample of heat exchangers that are directly cooled by the ICW system to verify that heat exchanger deficiencies, potential common cause problems, or heat sink performance problems that could result in initiating events or affect multiple heat exchangers in mitigating systems were being identified, evaluated, and resolved. No findings were identified as a result of these inspections.

As part of the 1Q 2013 inspection, the inspectors determined whether the plant's inspection of the UHS was thorough and of sufficient depth to identify degradation of the shoreline protection or loss of structural integrity. As part of the 4Q 2016 inspection, the inspectors reviewed testing, cleaning and inspection records to ensure that the associated activities provide reasonable assurance that heat transfer capability under current licensing and design basis conditions was being maintained. No findings were identified as a result of these inspections.

The ICW inspection program has been in effect since 1990, although ICW piping internal inspections have been performed since 1985. The program has proven experience in addressing the concerns and requirements of NRC Generic Letter 89-13. The NRC has performed several service water system operational performance inspections over the years. The results have been discussed in a number of inspection reports, and the program was found to be satisfactory.

The above examples provide objective evidence that audits and NRC inspections on the Open-Cycle Cooling Water System Program effectively identifies conditions and utilizes the CAP adequately to track their resolutions.

Enhancements to the AMP have been identified and implemented as a result of OE. An example of the AMP being enhanced by OE is the replacement of low alloy steel cap screws with stainless steel cap screws. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Open-Cycle Cooling Water System AMP, with enhancements, will provide reasonable assurance that aging will be adequately managed so that the intended function(s) of components within the scope of the AMP are maintained consistent with the CLB during the SPEO.

B.2.3.12 Closed Treated Water Systems

Program Description

The PTN Closed Treated Water Systems (CTWS) AMP, formerly a portion of the PTN Chemistry Control Program and PTN Systems and Structures Monitoring Program, is an existing AMP that manages the aging effects of loss of material due to corrosion, cracking due to SCC, and reduction of heat transfer due to fouling of the internal surfaces of piping, piping components, piping elements and heat exchanger components fabricated from any material and exposed to treated water. This AMP is delineated through the use of industry and internal OE, vendor recommendations, and EPRI TR-3002000590 (Reference B.3.106), “Closed Cooling Water Chemistry Guideline,” as applicable, and includes microbiological testing. The PTN CTWS AMP is a mitigation program that also includes a condition monitoring program to verify the effectiveness of the mitigation activities. This AMP consists of the following:

a. Water treatment, including 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 demonstrate that the water treatment program maintains the water chemistry within acceptable guidelines.

c. Component inspections/testing to determine the presence or extent of degradation.

The PTN CTWS AMP manages the above aging effects by using its water treatment procedure(s) to prevent/mitigate the causes of aging, and the component inspection procedure(s) to inspect for the aging effects of loss of material due to corrosion, cracking, and fouling (which reduces heat transfer). The PTN CTWS AMP manages the aging effects for all of the CTWSs at PTN, as identified in the pertinent AMR documents, and includes the internal surfaces of piping, piping components, piping elements, and heat exchanger components fabricated from any material and exposed to closed treated water. The components requiring inspection/testing are listed in the component inspection procedure, and the water treatment program for these components is in the water treatment procedure.

This AMP uses EPRI TR-3002000590 guidance to define its acceptance criteria for the normal operating ranges/limits for water chemistry concentrations, and parameters and water chemistry concentrations in closed treated water system are maintained within those limits.

The PTN CTWS AMP inspection procedure inspects components for any detectable loss of material, cracking, and fouling, as well as corrosion, flaking, pitting, gouges, loss of seal, leaking, and other surface irregularities on in-scope piping/components. This inspection procedure states that any piping corrosion that is greater than uniform light surface corrosion does not meet the acceptance criteria. Corrective actions (CRs) are initiated for any deficiencies noted during inspection walkdowns, then processed and evaluated in the CAP. Water chemistry concentrations that are not in accordance with the selected water treatment program are returned to the normal operating range within the prescribed timeframe for each action level. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, and loss of material.

NUREG-2191 Consistency

The PTN Closed Treated Water Systems AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M21A, “Closed Treated Water Systems,” with the exception identified below.

Exceptions to NUREG-2191

The PTN Closed Treated Water Systems AMP uses EPRI Technical Report TR 3002000590 rather than the NUREG-2191 specified EPRI Technical Report 1007820. This is because EPRI Technical Report 1007820 was superseded by EPRI Technical Report TR-3002000590. The newer EPRI guideline document encompasses new technology and captures lessons learned and industry OE.

Enhancements

The PTN Closed Treated Water Systems AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Expand the scope of the component inspections/testing to include any closed cooling/treated water system components that are identified in the AMR reports, which are not presently listed in the pertinent inspection procedure.
3. Parameters Monitored or Inspected	Perform visual inspections of all in-scope heat exchanger surfaces for cleanliness in order to ensure heat transfer capability. Alternatively, functional testing can be performed instead.
4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria	Align the program with the latest industry document, EPRI TR-3002000590, Closed Cooling Water Chemistry Guideline.

Element Affected	Enhancement
4. Detection of Aging Effects	Ensure the NUREG-2191 inspection requirements noted below are implemented, or point to another procedure that contains them. At a minimum, in each 10-year period during the SPEO, a representative sample of components is inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The sample population is defined as follows: • Twenty 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. • Ensure that visual inspections of the closed treated water systems components internal surfaces are conducted whenever their respective system boundary is opened.
5. Monitoring and Trending	Evaluate water chemistry testing results and component inspection/testing results against acceptance criteria to confirm that the sampling bases will maintain components' intended functions throughout the SPEO based on projected rate and extent of degradation.
6. Acceptance Criteria	Revise water treatment procedures to align with the latest industry document, EPRI TR-3002000590, Closed Cooling Water Chemistry Guideline (Reference B.3.106).
7. Corrective Actions	Ensure that the following additional inspections and actions are required if a post-repair/replacement inspection or subsequent inspection fails to meet acceptance criteria: • The number of increased inspections is determined in accordance with the PTN CAP; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria. • If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. • Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since PTN is a multi-unit site, the additional inspections include inspections at all of the units with the same material, environment, and aging effect combination. • The additional inspections are completed within the interval (e.g., RFO interval, 10-year inspection interval) in which the original inspection was conducted.

Operating Experience

Industry Operating Experience

As EPRI water chemistry guidelines are updated, PTN updates the governing chemistry procedure to ensure the latest guidelines are being followed. This includes latest recommendations for corrosion inhibitors and biocides added. The PTN Closed Treated Water Systems AMP uses EPRI Technical Report TR 3002000590 (March 2013) rather than the NUREG-2191 specified EPRI Technical Report 1007820 (April 2004) as EPRI Technical Report 1007820 was superseded by EPRI Technical Report TR-3002000590. The newer EPRI guideline document encompasses new technology and captures lessons learned and industry OE.

Site-Specific Operating Experience

The following examples of OE illustrate that the PTN Closed Treated Water Systems AMP will be effective in ensuring that intended functions are maintained consistent with the CLB for the SPEO.

In 2016, an external evaluation provided an area for improvement related to the chemistry program. Chemistry technicians inconsistently apply fundamental chemistry standards and laboratory work practices. This resulted in exceeding chemistry limits for the chilled water and feedwater system. As a result of this identified area for improvement, training was provided to the department on chemistry fundamentals. Other utilities' chemistry programs that had demonstrated chemistry program strengths were benchmarked, and the results of these benchmarking trips were used to enhance the chemistry program. Daily fundamentals topics are provided to the technicians by the supervisors to ensure adequate performance of job functions.

The quarterly health reports for the chemistry control program were WHITE for the first two quarters of 2012 due to issues unrelated to closed treated water systems (primarily condenser leaks that have been repaired) but has been GREEN up to the third quarter of 2017. There were no issues identified due to CCW chemistry being out of specifications from 2012 to 2017.

The system health reports for the Unit 3 and Unit 4 CCW system have hovered between YELLOW and GREEN between the first quarter of 2012 and third quarter of 2017. Issues lowering the health of the system are primarily related to inadequate CCW pump seals that were replaced, external corrosion of CCW piping that has since been either corrected by coating repairs or is being tracked and trended with planned repair or replacement activities based on corrosion rates, accelerated degradation of the ICW side of the CCW heat exchanger tubes that is currently being tracked and trended with number of plugged tubes, water infiltration issues with the CCW pump bearing grease that has been fixed by pump seal upgrade modifications, and fouling on the intake cooling water side of the CCW heat exchangers that is being managed by a supplemental CCW cooling loop and more frequent cleanings of the CCW heat exchanger. The system health reports from 2012 to 2017 do not document any cases of internal corrosion or heat exchanger fouling that could affect component intended functions.

The quarterly Unit 3 and Unit 4 risk significant ventilation system health reports were reviewed from 2012 to 2017. No internal surface age related identified deficiencies were identified associated with the chilled water portions of the system.

The quarterly Unit 3 and Unit 4 emergency diesel generator system health reports were reviewed from 2012 to 2017. No internal surface age related identified deficiencies were identified associated with the cooling water portions of the system.

During the Unit 4 2012 and Unit 3 2017 CCW heat exchanger eddy current testing, the following conditions were identified and corrected:

- Pitting and tube thinning/wastage was identified during eddy current testing of the Unit 4 CCW heat exchangers eddy current testing in 2012. As a result, 37 tubes were plugged in the 4A heat exchanger, no corrective action was required for the 4B heat exchanger, and seven tubes were plugged in the 4C heat exchanger. The pitting and tube thinning/wastage indications were located on the inside, or ICW side, of the tubing. No significant loss of material indications were noted on the outside, or CCW side, of the tubing.

- Pitting and tube thinning/wastage was also identified during the Unit 3 CCW heat exchangers inspections in 2017. As a result, 13 tubes were plugged in the 3A heat exchanger, 84 tubes were replaced in the 3B heat exchanger, and 138 tubes were replaced in the 3C heat exchanger. The pitting and tube thinning/wastage indications were located on the inside, or ICW side, of the tubing. No significant loss of material indications were noted on the outside, or CCW side, of the tubing.

In 2013, an active leak was identified in the 3A CCW pump vent line. Surface visual examinations of the inside diameter pipe revealed an indication approximately 1/4 inch in length. Penetrant indication showed a 7/8-inch flaw length at the 6th thread valley. The pipe was removed and forensic analysis was performed on the removed pipe. The pipe was replaced. The apparent cause was pump vibration causing damage to the vent line so flow meters were installed on the pump discharge so that operators can better monitor flow conditions.

A review of the CAP program from 2012 to 2017 for the systems under the scope of the Closed Treated Water Systems AMP did not identify any other deficiencies related to out-of-specification chemistry, internal corrosion, or heat exchanger fouling.

Enhancements to the AMP have been identified and implemented as a result of OE. An example of the AMP being enhanced by OE is through the benchmarking of other utilities' chemistry programs as described above. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Closed Treated Water Systems AMP, with exception and enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Program Description

The PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is an existing AMP, formerly part of the PTN Systems and Structures Monitoring Program.

This AMP evaluates the effectiveness of maintenance monitoring activities for cranes and hoists. The AMP also includes periodic visual inspections to detect loss of material due to corrosion, wear, cracking, and indications of loss of preload for load handling bridges, structural members, structural components and bolted connections. This AMP relies on the guidance in NUREG-0612 (Reference B.3.5), “Control of Heavy Loads at Nuclear Plants,” ASME B30.2 (Reference B.3.123), “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” B30.11 (Reference B.3.124), “Monorails and Underhung Cranes,” and other appropriate standards in the ASME B30 series. These cranes must also comply with the maintenance rule requirements provided in 10 CFR 50.65.

This AMP evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of SLR. This AMP also addresses the inspection and monitoring of crane-related structures and components to provide reasonable assurance that the handling system does not affect the intended function of nearby safety-related equipment.

This AMP manages the aging effects associated with handling systems that are within the scope of 10 CFR 54.4, as identified in pertinent AMR reports. Portions of the fuel handling system that are within the scope of this AMP include the bridges, structural members, and structural components, which are identified in the structures monitoring procedure. This scope includes the following cranes and load handling systems:

- Reactor building polar cranes
- Spent fuel cask crane
- Intake area bridge crane
- Turbine gantry cranes
- Charging pump monorails
- Safety injection pump monorails
- Main steam platform monorails
- Fuel handling bridge cranes
- Fuel transfer machines
- Spent fuel bridge cranes

- Fuel pool bulkhead monorails
- Intake Cooling Water (ICW) valve pit rigging beam
- Turbine plant cooling water (TPCW) basket strainer monorail

This AMP does not manage aging effects for the following load handling components: motors, trolleys, cables, hooks, rigging, etc. Such components are considered "active" components and are not screened into any AMP.

The surface condition of the in-scope structures and components and associated bolted connections is monitored by visual inspections. These inspections provide reasonable assurance that loss of material is not occurring and they check for general damage, including corrosion, cracking, erosion, discoloration, wear, pitting, gouges, dents, signs of surface irregularities, flaking, and missing parts. Visual inspection activities are performed by personnel qualified in accordance with site-specific procedures and processes.

Deficiencies are documented using the structures monitoring procedure and deficiencies are entered into the PTN CAP. The PTN program owner maintains a list of current deficiencies. Structures that are "acceptable with deficiencies" have the potential for propagation and are, therefore, trended for evidence of further degradation. Deficiencies that are identified during a visual inspection, which includes loss of material, deformation, cracking, and signs of loss of bolting preload, are entered into the PTN CAP for evaluation and corrective actions.

NUREG-2191 Consistency

The PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected 4. Detection of Aging Effects	Update the governing AMP procedure to clarify that the visual inspections of the in-scope bolted connections monitor for loss of material due to general corrosion, cracking, loose or missing bolts or nuts, and other conditions indicative of loss of preload.
4. Detection of Aging Effects 6. Acceptance Criteria 7. Corrective Actions	Update the governing AMP and inspection procedures to align with the 2005 version of ASME B30.2 (Reference B.3.123) and inspect for deformed, cracked, and corroded members, and for loose or missing fasteners, such as, but not limited to bolts, nuts, pins or rivets, as described in ASME B30.2, Section 2-2.1.3. According to ASME B30.2, inspections are performed within the following intervals: • “Periodic” visual inspections by a designated person are required and documented yearly for normal service applications (ASME B30.2, Section 2-2.1.1). • A crane that is used in infrequent service, which has been idle for a period of one year or more, shall be inspected before being placed in service in accordance with the requirements listed in ASME B30.2 paragraph 2-2.1.3 (periodic inspection).
4. Detection of Aging Effects	Update the governing AMP procedure to state that for the in-scope systems that are infrequently in service, such as containment polar cranes, periodic inspections are performed once every refueling cycle just prior to use.
6. Acceptance Criteria 7. Corrective Actions	Update the governing AMP procedure to state that any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload is evaluated, and repaired if necessary, in accordance with ASME B30.2 or other applicable industry standard in the ASME B30 series.

Element Affected	Enhancement
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria 7. Corrective Actions	Create a new inspection procedure for the portions of the Unit 3 and 4 fuel transfer machines that require aging management. Align this new procedure and its inspection frequency with the applicable ASME B30 standard. This new procedure performs visual inspections on the fuel transfer machines and provides reasonable assurance that the structural members and structural components (e.g., the rails) do not exhibit deformation, cracking, and loss of material due to general corrosion or wear. This new procedure also ensures that bolted connections are monitored for loss of material, cracking, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. Any visual indication of loss of material, deformation, cracking, or loss of bolting preload is evaluated and corrected in accordance with the respective ASME B30 standard.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria 7. Corrective Actions	Create a new inspection procedure for the Unit 3 and 4 spent fuel pool bridge cranes, and align the procedure with the 2005 version of ASME B30.2 (Reference B.3.123). The inspection frequency will be in accordance with ASME B30.2 Section 2-2.1.1. This new procedure is to specify performance of visual inspections on the spent fuel pool (SFP) bridge cranes to provide reasonable assurance that the bridges, structural members, and structural components do not exhibit deformation, cracking, and loss of material due to general corrosion or wear. Inspections to be performed by this new procedure also ensure that bolted connections are monitored for loss of material, cracking, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. Any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload is evaluated and corrected according to ASME B30.2.

Element Affected	Enhancement
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria 7. Corrective Actions	Create a new inspection procedure for the Unit 3 and 4 monorails and rigging beams listed below, and align the procedure with the 2004 version of ASME B30.11 (Reference B.3.124). The inspection frequency will be in accordance with ASME B30.11 Section 11-2.1.1. This new procedure is to specify performance of visual inspections to provide reasonable assurance that the bridges, structural members, and structural components do not exhibit deformation, cracking, and loss of material due to general corrosion or wear. The inspection specified by this procedure also ensures that bolted connections are monitored for loss of material, cracking, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. Any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload is evaluated and corrected according to ASME B30.11. This new inspection procedure, must clearly define inspection methodology and acceptance criteria for the following in-scope components: • Charging pump monorails • Safety injection pump monorails • Main steam platform monorails • Fuel pool bulkhead monorails • ICW valve pit rigging beam • TPCW basket strainer monorail

Operating Experience

Industry Operating Experience

With respect to industry OE from Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMPs at other plants, a review of five recent license renewal applications (LRAs) was performed. It was determined that other LRAs provided site-specific OE, but did not state any general industry OE that would require a written response from PTN. In addition, no recent NRC generic letters, requests, etc. requiring a response from PTN, with respect to crane aging management, were identified. NUREG-2191 states that there has been no history of corrosion-related degradation that threatened the ability of a crane to perform its intended function and that there have been no significant fatigue-related structural failures. NUREG-2191 did say that loss of bolt preload has occurred, but not to the extent that it has threatened the ability of a crane structure to perform its intended function.

Site-Specific Operating Experience

The PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as part of the PTN Systems and Structures Monitoring Program, is a mature and established program that remains effective. The effectiveness of the PTN Systems and

Structures Monitoring Program has been demonstrated in inspection notebooks compiled in support of the following NRC post-approval site inspections prior to entering the original PEO:

- March 2012 NRC post-approval site inspection for license renewal (ML12089A040, Reference B.3.62)
- July 2012 NRC post-approval site inspection for license renewal (ML12195A272, Reference B.3.60)
- November 2012 NRC post-approval site inspection for license renewal (ML12362A401, Reference B.3.61)

The three NRC site inspections listed above identified no findings or observation with respect to the PTN Systems and Structures Monitoring Program.

The PTN Systems and Structures Monitoring Program is also subject to internal plant health monitoring as documented by quarterly program health reports. The reports that were created during the PEO, from years 2012 through 2017, were collected and trended for the SLRA. The following examples from these plant health reports provide further objective evidence that the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as part of the PTN Systems and Structures Monitoring Program, remains effective in ensuring that component intended functions are maintained consistent with the CLB into and during the SPEO:

1. The structures monitoring program health reports for 2016 and 2017 identified a work order related to the intake area bridge crane (H2) associated bridge rail splices and bolting. The health report listed this work order because it was older than 6 months. The action request (AR) that led to this work order was initiated on February 4, 2015 as a result of a program inspection that identified corroded bolting and rail splices associated with the intake area bridge crane bridge rails. The rail splices were corroded to the point where the metal on the splice itself was flaking off.

   In response to this AR, the PTN engineering department performed a walkdown on March 3, 2015. The conclusion from the walkdown and a review of design drawings was that the rails were composed of uncoated carbon steel, whereas the intake beam structural steel was galvanized. The corrosion occurred due to the exposure of the carbon steel rails to the harsh salt-laden environment. The condition evaluation determined that existing damage did not represent a substantial structural concern. However, the condition evaluation recommended that the rails be inspected, coated (possibly galvanized), and repaired as required to ensure proper operation of the intake area bridge crane. The condition evaluation concluded that the condition of the rails did not adversely affect operation of the intake area bridge crane, however, a work order was created to implement the recommended repairs.

It is noted that the degradation identified in this OE item was identified by a structural monitoring related inspection. This is an example of how the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as implemented by PTN Systems and Structures Monitoring Program, self-identifies issues.

2. On March 12, 2015, corrosion was identified on the southwest end of the spent fuel cask crane (H4). The condition evaluation determined that this did not present a structural integrity issue and recommended that the corroded areas be prepared and painted over. The work order for the repair is in the planning phase and the repair will be completed using the PTN corrective maintenance process. No additional degradation has been observed as noted in Item 3 below.

3. On September 30, 2015, during the annual inspection for the spent fuel cask crane (H4), it was observed that the following items required repair, although none of those items were structural related:

   - Proximity switches for the Main and Aux hoist needed to be replaced.
   - The Main and Aux hoist emergency lowering manifolds were not working properly and required repairs.
   - All of the oils and hydraulic fluids needed to be changed per the vendor manual.
   - The annunciator horn worked intermittently and needed repair.

   Although the issues identified by this inspection were not aging effects associated with this AMP, this site OE is note-worthy, since it shows that frequently used cranes do undergo annual inspections as required by the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as implemented by PTN Systems and Structures Monitoring Program. Evidence of the in-scope aging effects (corrosion and wear-induced loss of material on bridge and structural components, cracking, and conditions indicating loss of preload) was not identified on the structural portions of the crane during the inspection. This inspection did not note any further degradation beyond what was identified on March 12, 2015. No subsequent ARs or CRs, as a result of subsequent inspections or other means, identified any in-scope aging effects associated with this crane. This reasonably shows that aging effects associated with the crane are adequately monitored.

4. During the April 23, 2013 installation of new access platforms for the intake area bridge crane, iron workers identified corrosion on hardware connecting the bridge section of the crane to the crane wheel assemblies. The PTN engineering department performed a condition evaluation on the condition to determine if any corrective actions were required.

   In response to this AR, a field inspection was performed to verify the extent of the corrosion degradation. The inspection determined that the bolts connecting the bridge section of the crane to the crane wheel assemblies (on the east and west side of the crane) had significant surface corrosion. From the inspection, it was observed that these bolts were never coated, and due to the nature of their harsh environment, surface corrosion had occurred.

The condition evaluation determined that the surface corrosion on the bolts had not affected the structural integrity of the bolts at that time, since the corrosion was only over the exterior surface area and it was verified that the bolts had lost minimal cross section, which would not affect the ability of the bolts to meet design requirements. It was determined that the corrosion would continue to propagate with time and eventually put the load-bearing capacity of the bolts at risk. In addition, the inspection also observed that the rail clips that attach the rails of the crane to the support structure were also corroded due to the same reason (no coating originally provided). The degradation on the east and west sides of the crane was more severe and the corrosion on the clips started to impact the support structure. The condition evaluation determined that the condition was required to be corrected as soon as possible to prevent irreparable damage on the support structure.

The condition evaluation determined that replacing the corroded bolting and clips with properly coated hardware was the most practical solution and would prevent the same degradation in the future. Therefore, the corroded rail clips and bolting were prepared, coated, and replaced as applicable by a work order.

It is noted that although this degradation issue was identified by modification workers, the intake area bridge crane is procedurally required to be inspected at a minimum of once every year, which assures that degradation will be identified prior to crane use, so that loss of intended function does not occur. Selecting replacement components and coatings that are resistant to aging effects demonstrates that the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as implemented by the PTN Systems and Structures Monitoring Program, is proactive in preventing similar issues from occurring in the future.

5. On April 9, 2009, during a paint removal activity for the spent fuel cask crane (H4), painters identified areas of corrosion and degradation in several locations of the spent fuel cask crane structure at Column 2 and Column A. A condition report (CR) evaluation completed on April 30, 2009 stated that the cause of the corrosion was due to environmental exposure. The CR evaluation pointed to a spent fuel cask crane upgrade project inspection report that presented the results of field inspections and testing of the existing spent fuel cask crane structure to determine the suitability of the existing components. A representative sample of the entire structure including structural members, bolted and welded joints, base plates and anchor bolts, and the general extent of corrosion was inspected. The report stated that the detailed structural analysis of the spent fuel cask crane revealed that extensive structural modifications to the spent fuel cask crane super structure were required.

A modification initiated activities to reinforce the existing crane structure, and replace and add new framing and foundations throughout the structure. Every connection detail associated with the spent fuel cask crane support structure was redesigned with new steel connections. Therefore, the connections and corrosion issues outlined in the CR evaluation were captured and addressed through the investigation and ultimate modification of the existing spent fuel cask crane structure. The modification was installed, with the last work order closed out on May 6, 2012.

Although this degradation issue was identified by modification workers, the spent fuel cask crane is procedurally required to be inspected at a minimum once a year, or prior to beginning a sequence that would remove spent fuel from the spent fuel pits in a cask. These inspections assure that degradation will be identified prior to crane use, so that loss of intended function does not occur. This OE also provides an example of how the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as implemented by the PTN Systems and Structures Monitoring Program, performed a detailed extent of degradation review, performed a thorough examination of the crane structure, and then reinforced the structure and redesigned weak and susceptible portions in order to stay proactive with respect to future corrosion.

6. On May 13, 2009, as part of the turbine gantry crane (H1) maintenance rule report walkdown, the PTN engineering department performed a visual inspection of the crane rails and hold-down features to identify any degradation which could affect the integrity of the turbine gantry crane support structure. A CR was initiated to address a degraded physical condition discovered on the west rail of the turbine gantry crane. Surface corrosion was identified on various sections of the rail as well as some of the hold down bolts and plates (steel splice plates). The degraded rails, hold-down bolts and plates required cleaning, re-inspection, and coating. It was noted that the east rail already had a protective coating (asphalt cover) which covered the rail connections and the bottom half of the rail, unlike the west rail which was exposed. It was noted that the majority of the hold down bolts and plates on the west side were showing signs of surface rust and flaking paint that was generally considered superficial and acceptable at the time. The recommended repair was to apply a bituminous coating/cover similar to the one used on the east rail of the turbine gantry crane per the recommended plant specification. A work order to repair and coat the turbine gantry crane rail was completed and the work order was closed on July 31, 2011.

   This is an example of how the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as implemented by PTN Systems and Structures Monitoring Program, identified and corrected a corrosion issue in its early phase, well before the structural integrity of the rails could be questioned.

7. On February 2, 2009, during the process of cleaning the coatings from the Unit 3 spent fuel bridge crane (3H201) rail clips, several of the rail clips and respective hold-down bolts that were not identified for replacement had failed. The damaged rail clip that was being repaired was located on the north end of the east rail, and during the repair and

mechanical cleaning, two additional rail clips became loose, and therefore, the job was stopped. The damage to the rails and rail bolting hardware is the result of corrosion.

The condition had been previously reported under a CR on October 31, 2004 and a similar condition was reported on another CR on November 3, 2008. The 2004 CR noted that both rails had recently been re-painted, but a leaking roof over one of the rails was identified as the reason for excess corrosion on that rail. The 2004 CR Corrective Action was to coat and repair. The 2008 CR corrective action replaced one deteriorated anchor plate. Based on Engineering and Projects Group inspections performed as a result of the 2008 CR disposition, the Unit 3 spent fuel bridge crane was tagged for limited use, with operation limited to those sections not affected by the reported corrosion. This limited operation was to ensure that the crane remained seismically qualified, precluding any potential adverse seismic interaction concerns. Engineering Evaluations were performed both in 2004 and 2008 and determined the spent fuel bridge crane would continue to perform its intended function.

As a result of the 2009 CR, a decision was made to replace both rails in Unit 3 immediately, followed with Unit 4 at a later time. Per the 2009 AR, the Unit 3 rail replacement work had been completed as of February 25, 2009. The work order that replaced the rails for the Unit 4 spent fuel bridge crane was closed on July 11, 2010.

It is noted that this was a pre-PEO issue. For the PEO and SPEO, quarterly program health reports are created to ensure that long-term aging issues (i.e., loss of material due to corrosion and wear, cracking, and conditions indicative of loss of preload, such as missing/loose bolts/nuts) are appropriately tracked, and generally the trend during the PEO is that crane issues do not remain on the health reports for multiple years. Another positive attribute associated with this AR includes the fact that repairs were immediately assigned to the spent fuel bridge crane for the opposite Unit as part of the extent of condition review.

8. On April 30, 2007, as part of the turbine gantry crane (H1) uprate effort to support the U3 generator rotor replacement project, a visual inspection was performed for the Unit 3 turbine gantry crane rails and hold down features to identify any degradation which could affect the integrity of the turbine gantry crane support structure. The inspection identified several hold-down bolts, plates, and clips that were corroded. Items that were severely corroded and impacted structural integrity of the crane were repaired prior placing the crane in service for the PTN3 generator rotor replacement. The condition was evaluated and a walkdown performed. The work order that performed the repairs that evaluated as being required was closed on December 11, 2007.

   This is an example of how the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as implemented by PTN Systems and Structures Monitoring Program, identified and corrected degradation prior to a critical crane usage task.

These OE examples show the following trends associated with the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, as implemented by the PTN Systems and Structures Monitoring Program:

1. The AMP has improved in recent years by self-identifying issues.

2. The corrective actions associated with this AMP generally repair/replace with components that are resistant to applicable aging effects, which is a proactive trait that prevents similar issues from occurring in the future.

3. The AMP evaluates extent of condition not only within that system, but also applies similar evaluation and corrective actions to the opposite Unit.

4. The AMP places crane-related aging issues on the quarterly plant health reports, so that they regularly receive appropriate attention and get resolved before becoming more degraded.

5. The AMP performs inspections to identify degradation and provide reasonable assurance that loss of component function does not occur during crane usage.

It has also been observed that sometimes work crews do identify degradation before an official inspection identifies it. This is a positive reflection of the work crews' healthy safety culture, where they report issues immediately, rather than waiting for an inspection at a later date. This AMP procedurally requires all in-scope cranes to be inspected either at a minimum of once every year or inspected prior to usage, and some cranes (e.g., spent fuel cask crane) are inspected once every year and prior to usage. The frequency of the required inspections provides reasonable assurance that age-related degradation is identified prior to crane use and that loss of component intended function does not occur. The OE listed above provides objective evidence that the inspection activities associated with this AMP are effective in identification age-related degradation and that the CAP is effectively used to take effective corrective measures prior to loss of component intended function. In addition, the crane load cycle limit TLAA for cranes within the scope of SLR (Section 4.7.6) concluded that the cranes will perform their component intended functions for 80 years of service and the crane design cycle fatigue is adequately addressed as required by NUREG-2191.

As stated in Section B.1.1, the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP for the SPEO is associated with the PTN Systems and Structures Monitoring Program that is credited in the PEO, as cranes are included in the structural walkdowns performed through that program. The PTN Systems and Structures Monitoring Program was found to be ineffective by the most recent AMP effectiveness assessment. This ineffectiveness is addressed in the Structures Monitoring AMP (Section B.2.3.35) and the External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23). As such, there is reasonable assurance that the PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP will manage the effects of aging through the SPEO to ensure that intended functions are maintained.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. Corrective actions have been initiated and completed to resolve AMP issues regarding the identified ineffectiveness of the Systems and Structures Monitoring AMP. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.14 Compressed Air Monitoring

Program Description

The PTN Compressed Air Monitoring AMP is an existing AMP, currently implemented as procedure 0-SMM-101.1, Instrument Air Periodic Testing, that provides assurance that compressed air system and supplied components susceptible to loss of material due to corrosion will continue to perform their intended function consistent with the current licensing basis (CLB) during the SPEO. These aging effects are currently managed under procedure 0-SMM-101.1. The PTN Compressed Air Monitoring AMP manages loss of material due to corrosion in compressed air systems and supplied components within the scope of SLR through the following:

a. Preventive monitoring for water (moisture) and other contaminants; and

b. Opportunistic inspection of component internal surfaces for indications of corrosion.

This AMP manages loss of material due to corrosion in components downstream of the air dryers in compressed air systems. Aging effects in locations upstream of the air dryers are managed by the PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.

This AMP ensures conditions remain as designed such that moisture is not collecting in compressed air system or supplied components, and air quality is retained so that loss of material due to corrosion is not occurring in the “dry air”. Moisture sensors at the outlet of the air dryers continuously monitor in-line dew point. Opportunistic internal visual inspections of critical components and other components are performed for signs of corrosion. The PTN Compressed Air Monitoring AMP is based on commitments made in response to NRC GL 88-14 (Reference B.3.33), “Instrument Air Supply Problems Affecting Safety-Related Components,” and incorporates industry guidance as warranted.

This AMP acknowledges dew point to be an indicator of moisture content and, therefore, maintains the dew point in the compressed air systems within the design parameters and manufacturer recommendations. Moisture indicators at the air dryer outlets are checked periodically to mitigate loss of material due to corrosion in downstream components. This AMP periodically checks the air quality in the compressed systems per manufacturer recommendations that are based on industry standards. The instrument air system, as well as the emergency diesel generator (EDG) air starter system, has in-line moisture instrumentation that is checked periodically (daily per manufacturer recommendations or during EDG air start tests) to ensure no or minimal moisture in the air supply.

NUREG-2191 Consistency

The PTN Compressed Air Monitoring AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M24, “Compressed Air Monitoring.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Compressed Air Monitoring AMP will be enhanced for alignment with NUREG-2191. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program 2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria	Formalize compressed air monitoring activities in a new governing procedure addressing both the instrument air and EDG air start systems. The following enhancements are also to be included into this procedure: a. Moisture and contaminant limits in the compressed air based on the manufacturer recommendations, pertinent industry guidance (ASME OM-2012 (Reference B.3.125), “Performance Testing of Instrument Air Systems Information Notice Light-Water Reactor Power Plants,” ANSI/ISA-S7.0.01-1996 (Reference B.3.120), “Quality Standard for Instrument Air,” and EPRI TR-108147 (Reference B.3.92), “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079”), and site OE. b. Opportunistic visual inspections of accessible internal surfaces for evidence of corrosion or corrosion products at frequencies based on industry guidance and site OE. These opportunistic visual inspections may be coordinated with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. Planned activities that open compressed air components, such as prefilter cleaning and inspection, are typically associated with dryers and related components. c. A description of qualifications for personnel performing (a) the inspections for evidence of corrosion or corrosion products and (b) air quality tests/checks. d. Trending for air quality, moisture content and signs of corrosion or corrosion products with checking for unusual trends and comparison to previous tests/checks. e. Acceptance criteria for compressed air moisture content based on manufacturer recommendations, pertinent industry standards and site OE. f. Address interface with PTN procurement and receiving functions regarding the quality of bottled gas (e.g., cover and backup nitrogen bottles) supplied to PTN. g. Periodic air samples are taken and analyzed for moisture content and corrosive contaminants. h. Reviews to ensure that proposed corrective actions are taken. Tracking and reporting of open corrective actions. Review of corrective action effectiveness.

Operating Experience

Industry Operating Experience

Other than IN 2008-06, there has been no new industry OE for Compressed Air Monitoring since PTN entered the current period of extended operation (PEO). IN 2008-06 provides notification of an incident at San Onofre Nuclear Generating Station Unit 2 in which an instrument air line failed at a soldered joint due to joint weakness and corrosion. While no specific requirements or standards were unmet in the event, the failure illustrates the importance of performing inspections that check for potential failure mechanisms. The Compressed Air Monitoring AMP considers the OE from IN 2008-06 and implements regular system monitoring activity to identify aging that could lead to loss of component intended function(s).

Site-Specific Operating Experience

The following review of site-specific operating experience during the first PEO, including past corrective actions, provides reasonable assurance that the Compressed Air Monitoring AMP effectively manages aging effects so that the intended functions of SSCs within the scope of the Compressed Air Monitoring AMP will be maintained during the SPEO.

1. In January 2017, a leak on 3-40-644, the instrument air supply valve for FCV-3-479 (feed water bypass control valve), was discovered. This was a small leak and no immediate action was required. Implementation of a work order for repair of the leak led to the discovery that the leak was due to a faulty fitting at the valve body, and no other issues were noted. With the valve isolated, a new fitting was installed along with the application of new thread sealant. These actions stopped the leak.

2. In August 2016, the instrument air system (IAS) dew point was high and out of specification. There was a step change from -60°F (satisfactory) to -1°F (unsatisfactory), exceeding the allowable value, after swapping to compressor 4CM in the lead. The subsequent engineering assessment concluded that the dryer desiccant resins had to be replaced and the dryer tower heaters repaired. These actions were completed, in accordance with PTN practice of replacing the resins upon failure, and the out-of-tolerance dew point readings were corrected.

3. In July 2015, an IAS leak was observed by a worker to the west of the 'B' stand-by steam generator feed pump underneath nearby cement blocks between valve NUMB-001, instrument air supply to future nuclear maintenance building, and valve 40-1384, instrument air to nuclear maintenance building isolation valve. It was isolated by closing valve NUMB 001. Engineering performed an extent of condition review and determined there were no additional issues with the capability of the IAS to perform its function. However, the review identified the vulnerability of sections of underground IAS piping to air leakage; included in the sections of piping identified as being at risk for potential leakage were those that were the subject of OE from 2005 to 2007, discussed in item 6 below. The July 2015 leak location is not within the license renewal boundary, and it was

determined that no license renewal intended functions were at risk of impairment by the leak. A work order is in the planning process for the repair of the piping. Additionally, instrument air flow readings were added to turbine building operator rounds to monitor for indications of possible leaks and assist in maintaining a sufficient air supply.

4. In order to address regular corrosion and associated aging-related issues, as well as to better equip the system to mitigate future aging effects, a large modification was implemented in the 2011 to 2012 timeframe. This modification replaced the major components of the instrument air system from the compressors to the supply header and the crosstie piping. The following changes were included in the modification: some carbon steel components were replaced with stainless steel components, drying and filtration components were upgraded to improve performance and capacity, instrumentation was added for improved system monitoring, and system configuration changes were made to improve draining. A third "swing" dryer was also installed that is capable of drying air for either unit, thus allowing a dryer to be taken out of service without placing the system in a configuration that creates a single point vulnerability. The engineering change (EC) addressed aging-related issues involving the loss of material due to corrosion on IAS components from the compressors to the supply header and cross-tie piping. Since the modification, no aging-related instrument air leaks have been observed in compressed air lines within the scope of SLR.

5. In September 2012, temporary instrument air compressor TC1 was placed in service to support maintenance on the 4CM IA compressor. As a result, the dewpoint temperature increased from approximately -109°F to 20°F, as noted in the operator rounds. This was likely caused by the configuration of the system; TC1 was connected downstream of mist eliminator 4F37, carrying excess moisture into the dryer pre-filters and overloading the dryer. The temporary instrument air compressor was removed from the system in EC 246990.

6. On three different occasions from 2005 to 2007, external corrosion was observed on compressed air piping, resulting in through-wall leaks in some cases. As these issues were found, they were evaluated for impact and necessary actions. In these cases, piping was either patched or carbon steel piping was replaced with stainless steel to improve corrosion resistance.

7. In 2005, while performing the annual PM on 3T9 instrument air dryer package, the block on one side was found to be corroded where the purge exhaust valve and the inlet valve are mounted. The purge exhaust valve assembly was also found in poor condition. The associated piping going to the north dryer package had internal corrosion.

   Engineering performed an evaluation and maintenance was performed to address the condition. All components affected by this condition were replaced in EC 246990 and EC 246991.

System Health Reports

System health reports for the instrument air system and emergency diesel generator system were reviewed for the 2012 to 2017 timeframe.

Instrument air system health scores below GREEN (GREEN indicates a healthy program) were consistently and mainly due to issues with the air compressors, which are beyond the scope of the Compressed Air Monitoring AMP. In some cases, dryer performance was also a contributor to low health scores (as discussed in item 2 of the site-specific OE). Otherwise, instrument air system health has been good.

EDG air components were consistently not significant contributors to low EDG system health scores. However, two minor contributors were found: one proactive action required to preclude degradation identified in Q2 2016 and one aging and obsolescence condition identified in Q3 2017. The required proactive action involved a Unit 3 air start check valve that was found to be sub-optimal for its application according to NRC guidance. A CAP item for valve replacement was created with a due date of April 2018. The aging condition involved a dryer skid dewpoint sensor that was found to be obsolete and was entered into the CAP with a resolution date of January 2018.

The above OE provides reasonable assurance that the Compressed Air Monitoring AMP is effective in detecting aging effects and utilizing the CAP to assess degraded conditions and implement corrective actions to maintain component and system intended functions. No adverse trend in performance was identified from the OE. Issues identified did not adversely impact the performance of license renewal intended functions. A review of the OE examples showed that, where age-related degradation has been identified, adequate corrective actions have been taken to prevent loss of intended function. Appropriate guidance for re-evaluation, repair, or replacement is provided in CAP documentation for age-related degradation that was found. To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Compressed Air Monitoring AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.15 Fire Protection

Program Description

The PTN Fire Protection AMP is an existing AMP, formerly a portion of the PTN Fire Protection Program. The PTN Fire Protection AMP for SLR is a condition monitoring program that manages aging effects (loss of material, cracking, and loss of seal) associated with fire barriers (penetration seals, fire barrier walls, ceilings, floors, fire damper assemblies, and other fire-resistant materials that serve a fire barrier function) and non-water suppression systems (Halon 1301 fire suppression system). The PTN Fire Protection AMP includes fire barrier inspections. The fire barrier inspection portion of this AMP requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors, fire damper assemblies, and other fire barrier materials, including structural steel fire-proofing, as well as periodic visual inspection and functional tests of fire-rated doors so that their operability is maintained. The PTN Fire Protection AMP also includes periodic inspection and testing of the halon fire suppression systems.

With respect to preventive actions, PTN has adopted the National Fire Protection Association (NFPA) 805 fire protection program to meet the requirements of 10 CFR 50.48(c) and ensure that regulatory requirements are met for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing SSCs important to safety.

Inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material. The acceptance criteria include:

a. No visual indications (outside of those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals.

b. No significant indications of cracking and loss of material of fire barrier walls, ceilings, floors, and in other fire barrier materials.

c. No visual indications of missing parts, holes, and wear.

d. No deficiencies in the functional tests of fire doors (i.e., the door swings easily, freely, and achieves positive latching).

Periodic inspections and hydro testing of the halon fire suppression system are performed to demonstrate that it is functional, and the surface condition of the halon system components is inspected for corrosion, nozzle obstructions, and other damage.

Visual inspection of at least 10 percent of each type of sealed penetration is performed at a frequency of every 18 months, which is in accordance with the NRC-approved fire protection program. Visual inspections on fire-rated assemblies (fire barrier walls, ceilings, floors, and other fire barrier materials including structural steel fire proofing) are conducted at a frequency of at least once every three years. Periodic visual inspections and functional tests are conducted on fire doors and their closing mechanism and latches are verified functional at least once per 12 months. Visual inspection on the fire damper assemblies are conducted at a frequency of once every three years.

The results of inspections and functional testing of the in-scope fire protection equipment are collected, analyzed, and summarized by engineers in health reports. The system and program health reporting procedures identifies adverse trends and prescribes preemptive corrective actions to prevent further degradation or future failures. When performance degrades to unacceptable levels, the PTN CAP is utilized to drive improvement. During the inspection of penetration seals, if any sign of abnormal degradation is detected within the sample, the inspection sample size is expanded, in accordance with the NRC-approved fire protection program used at PTN, to include an additional 10 percent of each type of sealed penetration.

NUREG-2191 Consistency

The PTN Fire Protection AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M26, “Fire Protection.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Fire Protection AMP will be enhanced as follows, for alignment with NUREG-2191. There are no new inspections required for SLR. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected 6. Acceptance Criteria	Update the fire damper inspection procedure(s) to specify inspections for corrosion and cracking on all in-scope fire damper assemblies, and state the acceptance criteria for the fire damper inspections as no visual indications of cracks or corrosion that could affect the component intended functions.
4. Detection of Aging Effects	Update the procedures that inspect penetration seals, walls, ceilings, floors, doors, fire damper assemblies, and other fire barrier materials to state that the inspectors are qualified per the NRC-approved fire protection program (NFPA 805) to perform such inspections.

Element Affected	Enhancement
5. Monitoring and Trending	Update the PTN Fire Protection AMP governing procedure to state that any degradation identified in the halon fire suppression system tests is to be documented and included in the trending analysis. Update the pertinent AMP procedure to state that, when practical, identified degradation is projected until the next scheduled inspection. Update the pertinent AMP procedure to state that the trending results of inspections are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) and the timing of subsequent inspections will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation.
7. Corrective Actions	Update the fire barrier penetration seal inspection procedure to state that if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, then inspection frequencies are adjusted as determined by the PTN CAP.

Operating Experience

Industry Operating Experience

As summarized in NUREG-2191, industry OE (NRC Information Notices (INs) 88-56, IN 91-47, IN 94-28, IN 97-70 and NRC Generic Letter 92-08) shows that fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes, electrical raceway fire barriers have experienced degradation such as small holes and cracking, and fire doors have experienced wear of the hinges and handles. PTN evaluates industry OE items for applicability per the FPL Fleet OE Program, and has specifically addressed these failure modes in plant specific fire barrier and door inspection procedures.

Site-Specific Operating Experience

As part of a committed enhancement prior to the end of the initial operating license period, PTN broadened the scope of the Fire Protection AMP to include inspection of the rubber expansion joints on the suction and discharge of the diesel fire pump engine piping to detect evidence of cracking or drying. As discussed in NUREG-1759 (i.e., the NRC Safety Evaluation Report for PTN LR), all other components having aging effects requiring management under the existing Fire Protection Program were included in the scope of the program. In the post-approval site inspection for license renewal (Reference B.3.60), NRC inspectors reviewed the licensing basis, program basis documents, implementing procedures and relevant condition reports to verify that the program was implemented as stated in the license renewal application and in NUREG-1759.

The inspectors verified that these requirements were adequately translated into the UFSAR. The inspectors verified that program documents were administratively updated to reflect their applicability to the license renewal program, interviewed the responsible plant personnel regarding this program and verified that the required procedural updates listed in the commitment were implemented. The status of administrative action items associated with the implementation of this commitment was considered "complete" for Units 3 and 4 in the licensee's CAP.

Additional examples of site-specific OE are provided below:

1. While performing monthly fire door inspections in May 2016, a fire door in the southeast corner of the Unit 4 reactor rod control equipment room was noted to have four holes in it caused by external corrosion. The deficiency was evaluated in accordance with the CAP and the door was repaired.

2. In June 2013, a crack was identified in a safety-related masonry wall as a result of the fire barrier inspections performed every 18 months. The crack was determined to be caused by the differential vibration between the turbine pedestal and the block wall. The crack was verified to be less than the procedural acceptance criteria of $\leq$ 1/16" in width. This same crack was identified previously in 2005 and dispositioned in the CAP. The crack has continuously been trended in the CAP. There has been no noticeable change in the size of the crack since 2005.

3. Internal QA audits of the Fire Protection program are conducted every two years. The most recent audit identified the need for improvement in the NFPA 805 transition process. The audit resulted in specific steps to ensure all committed NFPA 805 implementation items were completed to support the transition schedule.

A review of Fire Protection Program health reports since 2012 indicates that performance improvements are required specifically in the area of fire protection impairments (FPIs). PTN is working to reduce FPIs, and several ARs have been written to address improvement to the NFPA 805 Monitoring Program including improvements to the reliability criteria for fire protection SSCs. Improved inspection, testing and maintenance over time should improve component reliability and reduce FPIs. For example, fire protection program representatives now attend work order planning meetings to ensure that work orders related to fire protection equipment are coded with high priority designators for timely completion of repairs.

As stated in Section B.1.1, the Fire Protection Program, credited for the PEO, was found to be effective at managing aging in the December 2017 AMP effectiveness review. However, the program failed Element 2, Preventive Actions. The failed element was due to a deluge spray system functional test not being performed until after the required administrative due date but was promptly corrected. This failed element is associated with water-based fire protection, which is in the scope of the Fire Water System AMP credited for the SPEO. Therefore, this failed element does not apply to the Fire Protection AMP credited for the SPEO.

To date, no enhancements to the Fire Protection AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Fire Protection AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.16 Fire Water System

Program Description

The PTN Fire Water System AMP is an existing AMP, formerly a portion of the PTN Fire Protection Program. The PTN Fire Water System AMP is a condition monitoring program that manages aging effects associated with water-based Fire Protection System (FPS) components. This AMP manages loss of material, cracking, erosion, and flow blockage due to fouling by conducting periodic visual inspections, tests, and flushes performed in accordance with the 2011 Edition of NFPA 25 (Reference B.3.131). Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA 25. In addition to NFPA codes and standards, portions of the water-based FPS that are managed by this AMP are:

a. Piping that is normally dry but periodically subjected to flow; and

b. Piping that is unable to be drained or allows water to collect

This piping is subjected to augmented testing beyond that specified in NFPA 25, including: (a) periodic system full-flow tests at the design pressure and flow rate or internal visual inspections and (b) piping volumetric wall-thickness examinations.

The water-based FPS is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material is detected, and is sufficient enough to obstruct piping or sprinklers, then the material is removed, the source of the material is identified, and the source is corrected. Inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes for an adequate examination.

As a preventive measure, fire water systems are regularly checked for obstructions and flushed to remove blockage and obstructions, such as corrosion products and sediment as follows:

- The fire water supply and distribution system is flushed at least once every 18 months and at least once every 24 months for startup transformer deluge systems.
- The spray and/or sprinkler systems are flushed at least once every 18 months.
- The fire hose stations are checked for flow blockage at least once every 12 months.
- The fire hydrants are checked for flow blockage at least once every 18 months.

The PTN Fire Water System AMP monitors and inspects for the following fire water system parameters:

- The ability to maintain required system pressures and flow rates is required to be tested. Occurrences of pipe/component leakage are also visually identified during these tests.

- The ability to maintain required internal system conditions (i.e., no fouling or sediment blockage) is required to be tested. Pipe/component leakage can also be visually identified during these tests.

- Evidence of corrosion and erosion is monitored through regular visual inspections. Surface conditions are monitored visually to determine the extent of external material degradation. Visual examination will detect loss of material due to general, crevice and pitting corrosion, and loss of seal or cracking due to embrittlement. Internal conditions are monitored via leakage, flow and pressure testing. Internal loss of material (due to general, crevice and pitting corrosion, microbiologically-induced corrosion and selective leaching) and blockage due to fouling product build-up can be detected by changes in flow or pressure, leakage or by evidence of excessive corrosion products during flushing of the system.

The acceptance criteria are (a) the water-based FPS is able to maintain required pressure and flow rates, (b) minimum design wall thickness is maintained, and (c) no loose fouling products exist in systems that could cause flow blockage in the sprinklers or deluge nozzles.

If an obstruction inside piping or sprinklers is detected during pipe inspections, the material is removed and the inspection results are entered into the PTN CAP for further evaluation. An evaluation is conducted to determine if deposits need to be removed to determine if loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers is detected, a flush is conducted in accordance with the guidance in NFPA 25 (Reference B.3.131), Appendix D.5, “Flushing Procedures.” If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the PTN CAP.

NUREG-2191 Consistency

The PTN Fire Water System AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M27, “Fire Water System.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Fire Water System AMP will be enhanced for alignment with NUREG-2191. New augmented inspections (of portions of water-based FPS components that have been wetted but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves) are to be performed for SLR. This AMP will be implemented and its inspections and tests will begin no earlier than 5 years prior to the SPEO. Inspections or tests that are required to be completed prior to the SPEO will be completed no later than 6 months prior to the SPEO, or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
1. Scope of Program	Update the governing AMP procedure to state that sprinklers are either replaced before reaching 50 years in service or a representative sample of sprinklers from one or more sample areas is tested by using the guidance of NFPA 25 (Reference B.3.131), “Inspection, Testing and Maintenance of Water-Based Fire Protection Systems.”
3. Parameters Monitored or Inspected	Update AMP procedure(s) to state that volumetric wall thickness inspections are conducted on the portions of the water-based FPS components that are periodically subjected to flow but are normally dry. This will also require a new procedure to perform the volumetric wall thickness inspections.
3. Parameters Monitored or Inspected	Update AMP procedure(s) to state that additional volumetric wall thickness inspections are required to be made after surface irregularities, indicative of corrosion or erosion, are visually detected.
4. Detection of Aging Effects	Update AMP inspection/testing procedure(s) and develop new procedures to state that testing and visual inspections are performed in accordance with Table XI.M27-1 from NUREG-2191. This table, “Fire Water System Inspection and Testing Recommendations,” is based on NFPA 25 (Reference B.3.131), 2011 edition. Unless recommended otherwise, external visual inspections are to be conducted on an RFO interval.

Element Affected	Enhancement
4. Detection of Aging Effects	Develop new AMP inspection/testing procedure(s) to state that the portions of water-based FPS components that have been wetted but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves, are subject to augmented testing and inspections beyond those of NUREG-2191 Table XI.M27-1. The following augmented tests and inspections are to be conducted on piping segments that either cannot be drained or allow water to collect: • In each five-year interval, beginning five years prior to the SPEO, either conduct a flow test/flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of the piping segments that either cannot be drained or allow water to collect. • In each five-year interval of the SPEO, 20 percent of the length of piping segments that either cannot be drained or allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, erosion, MIC). The 20 percent of piping that is inspected in each five-year interval is in different locations than previously inspected piping. If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary. For portions of the normally dry piping that are configured to drain, such as pipe slopes towards a drain point, the tests and inspections of Table XI.M27-1 do not need to be augmented.
4. Detection of Aging Effects	Update AMP inspection/testing procedure(s) to state that if the environment (e.g., type of water, flowrate, temperature) and material that exist on the interior surface of the underground and buried fire protection piping are similar to the conditions that exist within the above grade fire protection piping, then the results of the inspections of the above grade fire protection piping can be extrapolated to evaluate the condition of buried and underground fire protection piping for the purpose of identifying inside diameter loss of material.

Element Affected	Enhancement
4. Detection of Aging Effects	Update AMP inspection/testing procedure(s) to state that inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. The inspections and tests are to follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes.
4. Detection of Aging Effects	Develop new AMP inspection/testing procedure(s) to state that the tanks that store fire water (RWTs T63A/B) must have their bottom surfaces inspected in accordance with the NUREG-2191, Table XI.M29-1. Specifically, for each 10-year period starting 10 years before the SPEO, a volumetric inspection is required to be performed from the inside surface of the tanks.
5. Monitoring and Trending	Update the AMP governing and trending procedures to state that where practical, degradation identified is projected until the next scheduled inspection. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the component intended functions throughout the SPEO based on the projected rate of degradation. Results of flow testing, flushes, and wall thickness measurements are monitored and trended by either the Engineering or Fire Protection Department per instructions of the specific test/inspection procedure. Degradation identified by flow testing, flushes, and inspections is evaluated. If the condition of the piping/component does not meet acceptance criteria, then a CR is written per the pertinent procedure and the component is evaluated for repair/replacement. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation.
5. Monitoring and Trending	Develop new AMP procedure(s) to continuously monitor and evaluate the FWS discharge pressure or continuously monitor and evaluate using equivalent methods (e.g., number of jockey fire pump starts or run time).
5. Monitoring and Trending	Update AMP procedure(s) to state that results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections is evaluated.

Element Affected	Enhancement
6. Acceptance Criteria	Update the governing AMP procedure to state that the minimum design wall thicknesses of the in-scope piping must be maintained.
6. Acceptance Criteria	Update the governing AMP procedure to point to the procedures which inspect the wall thicknesses and compare them to the minimum design thicknesses.
7. Corrective Actions	Update AMP procedure(s) and develop a new AMP procedure, if necessary, to state that if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation, then additional tests are conducted. The number of increased tests is determined in accordance with the PTN CAP; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval (i.e., five years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis is conducted to determine the further extent of tests. Since PTN is a multi-unit site, additional tests include inspections at all of the units with the same material, environment, and aging effect combination.

Operating Experience

Industry Operating Experience

As described below, industry operating experience indicates that fire water systems are susceptible to loss of material due to internal corrosion issues that can challenge system operability. PTN evaluates industry OE items for applicability per the FPL Fleet OE Program and takes corrective actions, when necessary.

In March 2013, the NRC issued IN 2013-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction." This IN describes the loss of function of fire protection sprinkler systems due to internal corrosion caused by air-water interaction. In November of 2013, PTN reviewed the IN for applicability and determined that some of the PTN deluge systems are susceptible to the internal corrosion identified in IN 2013-06. A CAP document was initiated to install low-point drains in the deluge suppression systems; however, further walkdowns were determined to be required prior to implementing the modifications. The low-point drains prevent the accumulation of water inside the piping after systems are actuated during the 18-month functional tests. The modification is yet to be installed at PTN pending the further walkdowns to determine the precise scope of work required. These walkdowns are scheduled to be completed in March of 2018 and will allow PTN to move forward with implementing the required modifications.

<u>Site-Specific Operating Experience</u>

The following review of site-specific OE, including corrective actions, audits, NRC inspections, and program health reports provides examples of how PTN is managing aging effects associated with the Fire Water System AMP.

1. During internal inspection of raw water tank (RWT) A in November 2012, rust was found on the inside of the access hatch. The rest of the RWT A internal surfaces were found to be satisfactory. An evaluation was performed that determined the rust does not jeopardize the function of RWT A in providing service water and fire protection water. A work request was created to repair or replace the RWT A access hatch. During exterior inspections of the RWTs in 2014 and 2016, areas of rust were also found. In 2014, RWT A showed rust on the roof, vent pipe, roof hatch bolts, overflow pipe, and an electrical conduit running along the ladder. Per PTN procedure, the RWTs are required to be rust-free. RWT B was found to be satisfactory. A trend work request was initiated to monitor the rust issue during following inspections. In 2016, RWTs A and B both showed rust areas that were determined to be minor in nature. A painting/deficiency report was generated with photos to correct the condition. Corrective actions are currently due in March of 2018 to clean and recoat both the internal and external rust areas of the RWTs.

2. In July 2016, while performing annual fire system valve cycling, a Unit 4 turbine building sprinkler system isolation valve developed a leak from the packing. The packing leak did not stop with valve on back seat. A work request was generated to tighten the packing nuts, which stopped the leak. No further corrective actions were required.

3. In November 2017, while performing the diesel driven fire pump annual surveillance test, the 1 ½-inch mini recirculation line ruptured during the test. This mini recirculation line is located outside in the raw water tank area. The mini recirculation line isolation valve was being closed during the test, per procedure, when the piping upstream of the valve ruptured and began spraying water at a rate of approximately 5 to 10 gallons per minute. The pump was immediately shut off and valves were closed to isolate the ruptured line. The ruptured line was then replaced and coated to prevent recurrence of external corrosion. In December 2017, a second leak on the same line developed from the elbow threads that were replaced. Repairs were completed to stop the leak and no further corrective actions were required.

4. The 2016 NRC Triennial Fire Protection Inspection Report (ML17012A378) resulted in no findings or unresolved issues related to water-based fire protection.

5. Fire Protection Program Health Reports were reviewed for 2012 through 2017. The program health reports indicate that performance improvements are required specifically in the area of fire protection impairments (FPIs). While not directly related to aging, FPIs are required when corrective actions (intrusive inspections/repairs) take place on the fire water system due to identified aging issues. The PTN Fire Protection AMP has had issues with preventive actions, which also results in increased FPIs. PTN is working to

reduce FPIs, and corrective actions are addressing improvement to the NFPA 805 Monitoring Program including improvements to the reliability criteria for fire protection SSCs. Improved inspection, testing and maintenance over time should improve component reliability and reduce FPIs. For example, fire protection program representatives now attend work order planning meetings to ensure that work orders related to fire protection equipment are coded with high priority designators for timely completion of repairs.

As stated in Section B.1.1, the Fire Protection Program, credited for the PEO, was found to be effective at managing aging in the December 2017 AMP effectiveness review. However, the program failed Element 2, Preventive Actions. The failed element was due to a deluge spray system functional test not being performed until after the required administrative due date. This failed element is associated with water-based fire protection, which is in the scope of the Fire Water System AMP credited for the SPEO. The PM scheduling issue was promptly identified by the program owner. Corrective actions were completed in December of 2017 to correct the PM scheduling issue.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN Fire Water System AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing condition monitoring AMP that was formerly the PTN Field Erected Tanks Internal Inspection Program. The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP manages the effects of loss of material on the outside and inside surfaces of metallic aboveground tanks that are located outdoors and constructed on concrete. One-time inspections were performed in accordance with PTN Field Erected Tanks Internal Inspection Program for the original license renewal between 2010 and 2012. As explained below, one-time inspections performed by the PTN Field Erected Tanks Internal Inspection Program for original license renewal will be converted to periodic inspections performed at 10-year intervals starting 10 years prior to the SPEO as part of the PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP. The Unit 3 and Unit 4 condensate storage tanks (CSTs), common demineralized water storage tank (DWST), Unit 3 and Unit 4 refueling water storage tanks (RWSTs), and the Unit 3 EDG fuel oil storage tank (FOST) are included in the scope of this AMP. Tanks supplying water to the fire water system are not within the scope of this program.

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP includes thickness measurements of tank bottoms to detect degradation and ensure corrosion from the inaccessible undersides will not cause a loss of intended tank function. The AMP also includes periodic visual inspection of tank internal surfaces and of the external tank-to-concrete interface. Inspections are conducted in accordance with site/fleet procedures that include inspection parameters such as lighting, distance, offset, and surface condition.

The material of construction for each tank is steel. Each tank has an external protective coating. None of the tanks are insulated and therefore, the accessible external surface of each tank shell is managed under the External Surface Monitoring of Mechanical Components AMP (Section B.2.3.23). Each of the tanks is coated on the interior surface. The coated interior surfaces are inspected in accordance with the requirements of the PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.29). Each tank is constructed with a concrete foundation. The concrete foundations are managed by the Structures Monitoring AMP (Section B.2.3.35). The tank design does not specify the use of sealant or caulking for the tank-to-concrete interface. The contents of the CSTs, DWST and RWSTs are treated water controlled under the Water Chemistry AMP (Section B.2.3.2). The contents of the EDG FOST is fuel oil controlled under the Fuel Oil Chemistry AMP (Section B.2.3.18).

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP monitors the potential loss of material of tank bottoms via UT thickness measurements of the tank bottoms that are performed whenever the tank is drained or at intervals not less than 10 years beginning 10 years prior to entering the SPEO. Visual inspections of the tank-to-concrete interface and tank internal surface are performed on the same 10-year interval. Subsequent UT inspections are conducted in different locations unless the evaluations associated with this AMP state the basis for repeated inspection in the same location.

The acceptance criteria for the internal visual inspection and bottom thickness of the tanks are the design corrosion allowance for the tank. Thus, any loss of material greater than the corrosion allowance for the tanks, as specified on the design drawings, requires evaluation or corrective action to ensure that the component intended functions of the tanks are maintained under all CLB design conditions. Results are evaluated against acceptance criteria for the in-scope tanks to confirm that the timing of the subsequent inspections will maintain the component intended functions throughout the SPEO based on the projected rate of degradation. Acceptance criteria for the tank-to-concrete interface inspection ensure there are no signs of degradation (minimal corrosion) or water intrusion. Any degradation of paints or coatings or evidence of corrosion are reported and require further evaluation to determine if repair or replacement of the paints or coatings should be conducted. Any deficiencies are documented, evaluated, and repaired as necessary.

Additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the PTN CAP; however, for inspections where only one in-scope tank of a material and environment combination is inspected, all tanks in that grouping will be inspected, including tanks from both units.

This AMP is required to be implemented with inspections and tests performed no earlier than 10 years prior to the SPEO and completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

NUREG-2191 Consistency

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks.”

Exceptions to NUREG-2191

None.

Enhancements

One-time inspections performed by the PTN Field Erected Tanks Internal Inspection program for original license renewal will be converted to periodic inspections in focused areas performed at 10-year intervals starting no earlier than 10 years prior to the SPEO. Inspections or tests that are required to be completed prior to the SPEO are completed no later than 6 months prior to SPEO or no later than the last RFO prior to SPEO. Scope will be expanded to include the Unit 3 EDG FOST and actions clarified when a tank does not meet acceptance criteria.

Element Affected	Enhancement
1. Scope 6. Acceptance Criteria	Include U3 EDG FOST in the scope of the program (including design corrosion allowance which is the same as for the CSTs).
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending	Convert one-time inspections for original license renewal to the following periodic inspections: a. Visual examination of tank internal surfaces.* b. Tank bottom thickness measurements.* * These additional inspections will be conducted each 10-year interval starting 10 years prior to entering the SPEO.
7. Corrective Actions	Clarify that increased inspections address each tank in a material environment combination in the same inspection interval, including tanks from both units, IF only one tank is inspected and does not meet acceptance criteria, which requires corrective action.

Operating Experience

Industry Operating Experience

As noted in NUREG-2191, industry experience reveals that there have been instances involving defects variously described as wall thinning, pinhole leaks, cracks, and through-wall flaws in outdoor and large metallic tanks. In addition, internal blistering, delamination of coatings, rust stains, and holidays have been found on the bottom of outdoor and large metallic tanks. In September 2013, the NRC issued Information Notice 2013-08, Refueling Water Storage Tank Degradation. It identified examples of leaks developing in RWSTs in stainless steel and aluminum tank. The leaks disrupted plant operation but did not challenge the structural integrity of the tanks. This industry operating experience was entered into the CAP and evaluated for applicability to PTN. NRC Information Notice 2013-08 is a reference used in the development of this program in NUREG-2191 and therefore the PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is consistent with this industry experience. However, it should be noted that the PTN RWSTs are not constructed of aluminum or stainless steel, and therefore the industry OE insights related to degradation of these material are not applicable to the PTN RWSTs.

Site-Specific Operating Experience

In October 2010, an inspection of the internal surfaces of the Unit 3 RWST was completed. The internal structure of the tank was found to be in excellent condition with no signs of structural distress, weld defects, or metal warping/pitting. There was no visible corrosion on the ceilings or walls and only minor rust staining found on the floor. These rust deposits were less than 1/8 inch in diameter and rested on the top of the coating and were not indicative of significant tank corrosion. The upper coating was removed at a sample spot to expose primer with no signs of degradation of the substrate. The coating system in the tank was found to be functional, but there was general softening and poor intercoat adhesion of the coating. The coating had been in service since 1972. Corrective actions were initiated and the tank interior was recoated in March 2012.

In March 2011, an inspection of the internal surfaces and coatings of the Unit 4 CST was performed. An equivalent inspection was performed on Unit 3 in 2012. The surfaces inspected were found to be free of defects with no blisters, checking, peeling or other lining defects.

In March and April 2011, an inspection of the internal surfaces and coatings of the Unit 4 RWST was completed. Small blisters on the coating in isolated areas of the tank wall were noted with diameters of ½ inch or less. When the topcoat of the blistered area was removed, the primer was found to be intact with no sign of corrosion. Several areas of corrosion deposits were observed on the tank floor. Corrective actions were initiated and the deposits were removed and minor corrosion of the substrate was observed. Ultrasonic thickness measurements were taken and the thinnest area observed was 0.295 inches, which exceeded the nominal thickness value specified in the tank design. The surface was cleaned and the coating repaired.

In September 2011, an inspection of the internal surfaces and coatings of the DWST was completed. The coatings were found to be in good condition with no significant degradation of surfaces on interior of the tank.

In March 2012, an inspection of the internal surfaces and coatings of the Unit 3 CST was performed. The internal surface condition was acceptable with no blisters, checking, peeling or other lining defects. An area of rust staining was observed in the area of the dome vent. The dome vent was modified and repaired to reduce rain intrusion. A similar modification was performed on the Unit 4 CST to improve the tank design.

In September 2012, as part of Seismic Walkdowns, a base plate of the Unit 03 EDG FOST was found rusted/corroded near anchor bolts (two places). A maintenance work order was generated and the base plate was cleaned and coated. The condition was deemed a cosmetic impact and no further surveillance was required. The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP credits the PTN External Surface Monitoring Program (Section B.2.3.23) for the performance of external inspections on a RFO frequency that would identify and correct equivalent conditions prior to a loss of intended function.

System Health Reports from 2012 through 2017, for systems containing tanks within the scope of this program were reviewed. No adverse impacts on system performance were identified in association with the specified tanks.

Each of the examples above demonstrates that the use of the PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is effective in identifying age-related degradation and that the CAP is utilized to evaluate degraded conditions to maintain component intended function consistent with the CLB.

Enhancements to the AMP have been identified and implemented as a result of OE. An example of the AMP being enhanced by OE was modification of the CST dome vent in 2012 to reduce the potential for corrosion. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.18 Fuel Oil Chemistry

Program Description

The PTN Fuel Oil Chemistry AMP is an existing AMP which is currently part of the Chemistry Control Program at PTN that manages loss of material and fouling in piping and components exposed to an environment of diesel fuel oil by verifying the quality of fuel oil and controlling fuel oil contamination as well as periodic draining, cleaning, and inspection of tanks. This AMP includes surveillance and maintenance procedures to mitigate corrosion of components exposed to a fuel oil environment.

Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the PTN TS (Reference B.3.147). Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, effectiveness is verified to provide reasonable assurance that significant degradation is identified and adequately managed and that the component intended function is maintained during the SPEO.

NUREG-2191 identifies those circumstances in which the fuel oil chemistry program is augmented to manage the effects of aging for SLR. For example, the PTN Fuel Oil Chemistry AMP may not be effective in stagnant areas. Accordingly, in certain cases as identified, verification of the effectiveness of the Fuel Oil Chemistry AMP is conducted. As discussed in NUREG-2191, for these cases, an acceptable verification program is the PTN One-Time Inspection AMP (Section B.2.3.20), where selected components at susceptible locations in the fuel oil system are inspected.

Section 6.8.4.e of the PTN TS (Reference B.3.147), Administrative Controls, requires that a diesel fuel oil testing program be established to implement required testing of both new fuel oil and stored fuel oil. This requirement is met by the PTN Fuel Oil Chemistry AMP procedures that analyze diesel fuel oil samples. This AMP also meets the PTN TS surveillance requirements to check and remove accumulated water from the EDG FOSTs (TS 4.8.1.1.2.d), verify fuel oil properties of new fuel (TS 4.8.1.1.2.e), and verify fuel oil properties of stored fuel (TS 4.8.1.1.2.f).

The scope of the PTN Fuel Oil Chemistry AMP includes the Unit 3 and 4 EDG FOSTs, the Unit 3 and 4 EDG day tanks, the Unit 3 EDG skid-mounted tanks, piping and other metal components subject to AMR that are exposed to an environment of diesel fuel oil. The scope of the program also includes piping and piping components and fuel tanks associated with the diesel-driven fire pump and the diesel-driven standby S/G feedwater (SSGF) pump that are exposed to an environment of diesel fuel. Acceptance criteria for fuel oil quality parameters are in accordance with the PTN TS (Reference B.3.147), ASTM D 975 (Reference B.3.130), and NRC RG 1.137 (Reference B.3.25).

NUREG-2191 Consistency

The PTN Fuel Oil Chemistry AMP, with exception and enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M30, “Fuel Oil Chemistry.”

Exceptions to NUREG-2191

PTN will take an exception to the cleaning and inspection requirements specified in Element 4 of the GALL Fuel Oil Chemistry program, since the design of the Unit 3 EDG skid tanks and the SSGF pump skid tank do not allow for complete draining, cleaning, 100 percent internal visual inspection, or volumetric inspection of the bottom of the skid tanks. These skid tanks are integral to the baseplate of the diesel engine and generator/pump assembly and are not a stand-alone tank. As an alternative to the GALL Element 4 requirements, PTN will drain and clean the Unit 3 EDG skid tanks and SSGF pump skid tank to the extent practical. Visual inspection of accessible locations of the skid tank internals will be performed and volumetric inspection of accessible portions of the skid tank as close to the bottom of the skid tank as possible will be performed.

Enhancements

The PTN Fuel Oil Chemistry AMP will be enhanced as follows, for alignment with NUREG-2191. This AMP also will create a new procedure for the draining, cleaning and inspection of the diesel-driven fire pump fuel tank and the SSGF pump skid-mounted tank. This AMP is to be implemented and its inspections and tests begin no earlier than 10 years prior to the SPEO. The inspections and tests are to be completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
2. Preventive Actions	PTN procedures will be enhanced to address periodic cleaning of the Unit 3 and 4 EDG day tanks, Unit 3 EDG skid tanks, the diesel-driven fire pump fuel tank, and the SSGF pump skid-mounted tank as described in Element 4 enhancements. PTN procedures will be enhanced to address periodic draining of accumulated water in the diesel driven fire pump fuel tank, and the SSGF pump skid-mounted tank.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	PTN procedures will be enhanced to address the analysis of stored fuels in the EDG FOSTs, the EDG day tanks, the EDG skid-mounted tanks, the diesel-driven fire pump fuel tank, and SSGF pump skid-mounted tank describing analytical techniques and test frequencies for determining water and sediment content, total particulate concentration, and microbiological contamination levels. PTN procedures addressing EDG FOST cleaning and inspection activities will be enhanced to include thickness measurements of the bottoms of the tanks or, in the case of the Unit 4 FOSTs, thickness measurements of the carbon steel tank liners. PTN procedures will be enhanced to address periodic tank cleaning, and visual or alternative internal inspections, and thickness measurements of the bottoms of the EDG day tanks, EDG skid tanks, diesel-driven fire pump fuel tank and SSGF pump fuel tank as described in Element 4 of this AMP.
4. Detection of Aging Effects	EDG FOSTs, day tanks, and skid-mounted tanks; diesel-driven fire pump fuel tank; and SSGF pump skid-mounted tank sampling procedures will clearly address multilevel and/or bottom samples consistent with PTN equipment configuration and to identify sampling considerations consistent with those described in applicable industry standards such as ASTM 4057 (Reference B.3.126). EDG FOSTs, day tanks and skid-mounted tanks and diesel-driven fire pump fuel tank and SSGF pump skid-mounted tank cleaning and inspection activities are to be expanded to include thickness measurements of the bottoms of the tanks or, in the case of the Unit 4 EDG FOSTs, thickness measurements of the carbon steel tank liners, as an additional measure to provide reasonable assurance that loss of material is not occurring. For the Unit 3 EDG skid tank and SSGF pump skid-mounted tank, bottom thickness measurements are not possible due to tank/engine integral design; therefore, the volumetric inspection will examine accessible locations as close as possible to the tank bottom. PTN procedures addressing EDG FOSTs, day tanks and skid-mounted tanks and diesel driven fire pump fuel tank and SSGF pump skid-mounted tank cleaning and inspection activities are to require that any degradation identified during visual inspection be supplemented with volumetric inspections.

Element Affected	Enhancement
4. Detection of Aging Effects (continued)	The design of the Unit 3 EDG skid tanks and the SSGF pump skid-mounted tank do not allow for complete draining, cleaning, 100 percent internal visual inspection, or volumetric inspection of the bottom of the skid tanks. These skid tanks are integral to the baseplate of the diesel engine and generator/pump assembly and are not a stand-alone tank. Visual inspection of accessible locations of the skid tank internals will be performed and volumetric inspection of the skid tank as close to the bottom of the skid tank as possible will be performed. Prior to the SPEO, a one-time inspection of selected components exposed to diesel fuel oil is to be performed in accordance with the PTN One-Time Inspection AMP (Section B.2.3.20) to verify the effectiveness of the Fuel Oil Chemistry AMP. PTN procedures addressing EDG FOSTs, day tanks and skid-mounted tanks and diesel-driven fire pump fuel tank and SSGF pump skid-mounted tank to be enhanced to clearly require that, during the 10-year period prior to the SPEO and at least once every 10-years during the SPEO, each diesel fuel tank 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 using the tank-specific methods described above.
5. Monitoring and Trending	PTN procedures for fuel oil sampling and testing are to be enhanced to require periodic testing of the stored fuel oil in the EDG FOSTs, EDG day tanks, EDG skid-mounted tanks, diesel-driven fire pump fuel tank and the SSGF pump skid-mounted tank for biological activity consistent with those described in applicable industry standards. PTN procedures are to be enhanced to ensure that all diesel fuel oil tanks in the scope of SLR are periodically sampled for water accumulation and particulates. PTN procedures for fuel oil testing and sample analysis to require trending of the results of diesel fuel oil sample analyses.

Element Affected	Enhancement
6. Acceptance Criteria	Provide acceptance criteria, consistent with industry standards, for the testing requirement and approach used to detect the presence of water, particulates, and microbiological activity in stored diesel fuel within all diesel fuel tanks in the scope of SLR. Provide that bottom wall thickness measurements of the EDG FOSTs, EDG day and skid mounted tanks and the diesel-driven fire pump fuel tank and the SSGF pump skid-mounted tank, or, in the case of the Unit 4 EDG FOSTs, thickness measurements of the carbon steel tank liners as described in Element 4 of this AMP, be measured, trended and evaluated against the applicable design thickness and corrosion allowance.
7. Corrective Actions	Provide corrective actions, such as addition of a biocide, to be taken should testing detect the presence of microbiological activity in stored diesel fuel. Provide for the immediate removal of any water found during sampling of an EDG day tank or skid-mounted tank, the diesel-driven fire pump fuel tank, or the SSGF pump skid-mounted tank.

Operating Experience

Industry Operating Experience

To date, the Fuel Oil Chemistry AMP has been effective in preventing unacceptable degradation of the in-scope systems containing fuel oil. Review for recent industry operating experience did not identify any significant experience related to the Fuel Oil Chemistry AMP.

Site-Specific Operating Experience

The effectiveness of the PTN Fuel Oil Chemistry AMP, from renewed license issuance in June 2002 to entering the PEO in July of 2012, was confirmed by the July 2012 NRC post-approval site inspection (Inspection reports 05000250/2012008 and 05000251/2012008) for the original period of extended operation (PEO). This post-approval site inspection did not identify any findings or observations related to the PTN Fuel Oil Chemistry AMP. The following examples of OE provide objective evidence that the PTN Fuel Oil Chemistry AMP will be effective in ensuring that intended functions are maintained consistent with the CLB for the SPEO.

1. The chemistry program health reports were reviewed from 2012 to 2017. No identified deficiencies were identified related the systems and components within the scope of this AMP and the diesel fuel oil portion of the chemistry program has been GREEN for every quarter.

2. A chemistry audit was completed in December of 2016. The only deficiencies related to diesel fuel oil were related to a fuel oil spill near the diesel driven air compressor and inadequate logging of diesel engine run times, both of which are unrelated to aging.

3. A chemistry audit was completed in February of 2015. The results of this audit state that diesel fuel oil was tested to ensure high-quality fuel oil was maintained during normal and emergency conditions. Fuel delivery was verified to meet the acceptance criteria and the records were reviewed by a chemistry supervisor. QA records were kept for each diesel fuel delivery. If a shipment of diesel fuel did not meet acceptance criteria, an AR was written and the shipment was rejected. In these cases, deficiencies were entered into the CAP, evaluated, corrective actions taken, and closed.

4. During performance of the U3 Diesel fuel oil storage tank (FOST) accumulated water removal procedure in December of 2014, particulates were identified when draining the sample to verify no water. Chemistry performed sampling of the FOST and determined that the particulate results were well within the acceptance criteria of 10 mg/L. In addition, the water and sediment results were within specification limits. Chemistry continued to trend FOST sampling results following this event.

5. In 2014, as a result of Diesel Fuel Oil testing only being performed once a month, it was determined that there is an opportunity for inadequate knowledge transfer between technicians. In response to this determination, Chemistry conducted refresher training on Diesel Fuel Oil Sampling, and testing. This training included specific requirements listed in the Tech Specs, and required each technician to demonstrate an understanding of sample sequences for Truck and Tank analysis.

6. As part of preshipment vendor analysis, in January of 2014, PTN Chemistry was notified by the vendor that the first lubricity test yielded a 520-micron result. The PTN allowable range for lubricity is less than 520 microns. Subsequent tests yielded results of 460 and 400 microns respectively. Given the first test did not pass and the large variance in test results, the vendor was requested to re-test the preshipment. Upon retest, a value of 540 microns was obtained. The diesel fuel oil shipment was subsequently canceled.

7. In 2013 and 2014 ASTM issued DF21302 #2 and DF21402 #2 which are the reports for Diesel Fuel Oil Proficiency Testing. The specific parameters are required to be tested once a year, and are part of the Interlaboratory sample program. PTN Chemistry passed both required analyses.

8. In March of 2013, as part of pre-shipment acceptance analysis for a delivery of diesel fuel, test results for Biodiesel content were determined to be "high out of spec" at 0.16 percent versus an allowable range of less than 0.1 percent Biodiesel content. The fuel shipment was not accepted for delivery.

9. As part of pre-shipment acceptance analysis in May of 2013, bulk sample testing test results for Biodiesel content were determined to be "high out of spec" at 0.11 percent

versus an allowable range of less than 0.1 percent Biodiesel content. Upon evaluation, it was determined that the issue was an apparent discrepancy in the testing methodologies between PTN Chemistry and the vendor's labs. PTN Site chemistry was able to confirm the shipment met the allowable of less than 0.1 percent Biodiesel fuel content range. Evaluation of the fuel determined that it was acceptable for site use and that it did not pose an operability concern.

10. In 2013, multiple consecutive fuel shipments were found to have API (American Petroleum Institute) gravity sample results approaching the upper allowable limits for diesel fuel. As a consequence of these results, the vendor was requested to test and report API gravity in the FOST prior to shipment. The technical specification Diesel Fuel Oil Testing Program requires verification that API Gravity is within limits prior to addition to the tanks.

11. In March 2012, the API gravity spec for receiving fuel oil truck was 39.0 degrees API. The last tanker sample from the leased tanks delivered to PTN showed 38.5 API gravity. The Certificate of Analysis from Palm Dale showed 38.1 API gravity and the analysis from Herguth Laboratories showed 39.0 API gravity. This is at the upper end of the spec. No limits have been exceeded for fuel accepted on site.

These examples provide objective evidence that the Fuel Oil Chemistry AMP sampling, inspection and cleaning activities are effective in identification of fuel oil contamination and that the CAP is effectively used to take corrective actions prior to loss of material and fouling in components exposed to an environment of diesel fuel oil. Adequate corrective actions were taken to prevent recurrence. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Therefore, there is objective evidence that continued implementation of the AMP, with the identified exceptions and enhancements, will effectively identify and address degradation prior to component loss of intended function. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Fuel Oil Chemistry AMP, with exception and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.19 Reactor Vessel Material Surveillance

Program Description

The PTN Reactor Vessel Material Surveillance AMP is an existing AMP, formerly a portion of the PTN Reactor Vessel Integrity Program. This AMP meets the requirements of 10 CFR Part 50, Appendix H, which requires the implementation of a reactor vessel material surveillance program when the peak neutron fluence at the end of the design life of the vessel exceeds 10^{17} n/cm^2 (E > 1 MeV). The purpose of this AMP is to monitor the changes in fracture toughness to the ferritic reactor vessel beltline materials. As described in Regulatory Issue Summary 2014-11 (Reference B.3.37), beltline materials are those ferritic reactor vessel materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the license period (for example, the SPEO), which are evaluated to identify the extent of neutron radiation embrittlement for the material. The surveillance capsules contain reactor vessel material specimens and are located near the inside vessel wall in the beltline region so that the specimens duplicate, as closely as possible, the neutron spectrum, temperature history, and maximum neutron fluence experienced at the inner surface of the reactor vessel. Because of the location of the capsules between the reactor core and the reactor vessel wall, surveillance capsules typically receive neutron fluence exposures that are higher than the inner surface of the reactor vessel. This allows surveillance capsules to be withdrawn and tested prior to the inner surface receiving an equivalent neutron fluence so that the surveillance test results bound the conditions at the end of the SPEO.

This AMP addresses neutron embrittlement of all ferritic reactor vessel beltline materials as defined by 10 CFR Part 50, Appendix G, as the region of the reactor vessel that directly surrounds the effective height of the active core and the adjacent regions of the reactor vessel that are predicted to experience sufficient neutron damage to be considered in the selection of the limiting material with regard to radiation damage. Materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the SPEO are considered to experience sufficient neutron damage to be included in the beltline. Materials monitored within the PTN license renewal materials surveillance program continue to serve as the basis for this AMP.

The surveillance portion of this AMP adheres to the requirements of 10 CFR Part 50, Appendix H as well as the ASTM standards incorporated by reference in 10 CFR Part 50, Appendix H. The surveillance capsule withdrawal schedule is documented in the PTN Reactor Material Surveillance Program, which is the implementing document for this AMP. Surveillance capsules are designed and located to permit insertion of replacement capsules.

This program includes withdrawal and testing of the X4 surveillance capsule. This capsule is demonstrated as being within one to two times the peak reactor vessel neutron fluence of interest at the end of the SPEO in the TLAAs for USE, PTS, and P T limits.

FPL was a member of the Babcock & Wilcox Owners Group (B&WOG) reactor vessel working group. The B&WOG designed an irradiation surveillance program (Master Integrated Reactor Vessel Program, MIRVP) (Reference B.3.144) in which member materials are irradiated at host plants. PTN materials are being irradiated in both reactor vessels (Units 3 and 4) at the site and in the MIRVP. The MIRVP Charpy values and direct fracture toughness (master curve) data will be used as supplemental data. To date this program has developed one set of Charpy values and two sets of irradiated “master curve” data relative to the PTN beltline materials. The PWROG is now the mechanism for the previous B&WOG reactor vessel working group activities, and FPL is a member of the PWROG. Recent changes to the MIRVP are currently being evaluated by the NRC. However, the implementation of the MIRVP in this Reactor Vessel Material Surveillance AMP is only for supplemental data and is not a part of the NRC-approved surveillance program. This AMP relies fully on onsite capsules.

The objective of the PTN Reactor Vessel Material Surveillance AMP is to provide sufficient material data and dosimetry to (a) monitor IE to a neutron fluence level which is greater than the projected peak neutron fluence of interest projected to the end of the SPEO, and (b) provide adequate dosimetry monitoring during the SPEO. Dosimetry monitoring during the SPEO is performed by the PTN Neutron Fluence Monitoring AMP (Section B.2.2.2). The PTN Reactor Vessel Material Surveillance AMP provides data on neutron embrittlement of the reactor vessel materials and neutron fluence data. These data are used to evaluate the TLAAs on neutron IE (e.g., USE, PTS, P-T limits evaluations, etc.) as needed to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 and 10 CFR 50.61a for the SPEO, as described in NUREG-2192, Section 4.2. This AMP has one capsule that will attain neutron fluence between one and two times the peak reactor vessel wall neutron fluence of interest at the end of the SPEO. The AMP withdraws, and subsequently tests, the capsule(s) at an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel neutron fluence of interest at the end of the SPEO. Test results from this capsule are reported, consistent with 10 CFR Part 50, Appendix H.

All pulled and tested samples placed in storage with reactor vessel neutron fluence less than 37.5 percent of the projected neutron fluence at the end of the SPEO, may be discarded. All pulled and tested samples with a neutron fluence greater than 37.5 percent of the projected reactor vessel neutron fluence at the end of the SPEO and all untested capsules are placed in storage (these specimens and capsules are saved for possible future reconstitution and reinsertion use) unless the NRC has approved discarding the pulled and tested samples or capsules. Tested surveillance specimens may be withdrawn from storage and used in research activities (e.g., microstructural examination, mechanical testing, and/or additional irradiation) without NRC approval as a sufficient number of specimens will remain.

This PTN Reactor Vessel Material Surveillance AMP is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in the USE as a function of neutron fluence and irradiation temperature. The data from this surveillance program are used to monitor neutron irradiation embrittlement of the reactor vessel, and are inputs to the neutron embrittlement TLAAs. The PTN Reactor Vessel Material Surveillance AMP is also used in conjunction with the proposed PTN Neutron Fluence Monitoring AMP.

All surveillance capsules, including those previously withdrawn from the reactor vessel, must meet the test procedures and reporting requirements of the applicable ASTM standards referenced in 10 CFR Part 50, Appendix H, to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the surveillance capsule withdrawal schedule must be approved by the NRC prior to implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3.

NUREG-2191 Consistency

The PTN Reactor Vessel Material Surveillance AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M31, “Reactor Vessel Material Surveillance.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

In 2014, AREVA discovered there was a Charpy Specimen orientation issue for reactor vessel beltline plates and forgings. Forging materials data with unspecified Charpy specimen orientations were identified that may have been used to establish material values for certain reactor vessels.

Site-Specific Operating Experience

In October 2014 an interim evaluation was performed to address the AREVA Charpy Specimen orientation issue mentioned above and because AREVA was unable to determine if this observation had an impact on PTN reactor vessel evaluations at that time. The results of the evaluation concluded that the 48 EFPY P-T limit curves contained in PTN Technical Specifications, Amendments 261 and 256, remained valid and were unaffected. There were no changes required for cool-down or heat-up P-T limit curves or Low Temperature Over Pressure (also called Cold Overpressure Mitigation System) setpoints for PTN Units 3 and 4. In addition, the forging materials identified in the AREVA Charpy issue remain below the 10 CFR 50.61 screening limit and were unaffected. AREVA concurrently performed an independent evaluation of the initial properties (RT_{NDT}) reported for the PTN Units 3 and 4 reactor vessel beltline forgings and concluded that the existing initial RT_{NDT} values are consistent with existing regulations.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Reactor Vessel Material Surveillance AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.20 One-Time Inspection

Program Description

The PTN One-Time Inspection AMP is a new AMP that consists of a one-time inspection of selected components to accomplish the following:

a. Verify the effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO. The aging effects evaluated are loss of material, cracking and fouling.

b. Confirm the insignificance of an aging effect for situations in which additional confirmation is appropriate using inspections that verify unacceptable degradation is not occurring.

c. Trigger additional actions that ensure the intended functions of affected components are maintained during the SPEO.

Determination of the sample size will be based on 20 percent of the components in each material-environment-aging effect group up to a maximum of 25 components at each unit. The sample size of components will also be based on OE. Identification of inspection locations will be based on the potential for the aging effect to occur. Examination techniques will be established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria will be based on applicable ASME Code or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. The need for follow-up examinations will be evaluated based on inspection results if age-related degradation is found that could jeopardize an intended function before the end of the SPEO.

The PTN One-Time Inspection AMP will not be used for structures or components with known, age-related degradation mechanisms, or when the material-environment-aging effect group in the SPEO is not expected to be equivalent to that in the prior operating period. In these cases, periodic site-specific inspections will be performed.

The PTN steam generator transition cone was cut in the middle to replace the bottom part of the steam generator. The resulting new circumferential weld is a field weld, as opposed to the upper and lower transition cone welds which were performed in a controlled manufacturing facility. To identify the effectiveness of the water chemistry program, the PTN One-Time Inspection AMP will perform an inspection on the new transition cone weld of the steam generators. This inspection will be a volumetric inspection consistent with the techniques currently in place for the original transition cone welds.

The PTN One-Time Inspection AMP will be a condition monitoring program that does not include methods to mitigate or prevent age-related degradation. The PTN AMP will monitor parameters directly related to the age-related degradation of a component. Examples of parameters monitored and the related aging effects are provided in NUREG-2191, Table XI.M32-1. For observed degradation, acceptance criteria will be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. Ultrasonic thickness measurements will be compared to predetermined limits. Crack-like indications are not acceptable. Where it is reasonable to project observed degradation out to the end of the SPEO, the projected degradation shall not:

- Affect the intended function of a system, structure, or component.
- Result in a potential leak.
- Result in heat transfer rates below that required by the CLB in order to meet design limits.

The PTN One-Time Inspection AMP will have a new governing and inspection procedure created in accordance with NUREG-2191, Section XI.M32. This AMP will be implemented and its inspections begun no earlier than 10 years prior to the SPEO and completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

NUREG-2191 Consistency

The PTN One-Time Inspection AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M32, “One-Time Inspection.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

The elements that comprise inspections associated with this AMP (the scope of the inspections and inspection techniques) are consistent with industry practice. A review of the PTN site-specific OE associated with detection of aging effects adequately demonstrates that this AMP is capable of detecting the presence or noting the absence of aging effects in the components, materials, and environments where one-time inspection is used to confirm system-wide effectiveness of another preventive or mitigative AMP.

PTN participates in license renewal working groups sponsored by the Nuclear Energy Institute. Information sharing in these groups and use of NUREG-2191 Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report will ensure that industry resources and experience are incorporated into the PTN One Time Inspection program.

Site-Specific Operating Experience

Since this is a new AMP, a review was conducted of PTN maintenance and inspection activities that employ the same inspection methods as will be used in the new one-time inspection program to determine what aging mechanisms have been observed. Several examples are given:

1. In 2007,while performing a routine clean and inspect of the 3B emergency diesel generator air solenoid drain valves, it was discovered that the carbon steel oil separator drain line was not draining properly due to corrosion particles clogging the screen filters of the drain valve. An evaluation was performed and determined that the safety function of the EDG was not compromised. The 3A drain line was inspected and no corrosion was found. Unit 4 lines are made of stainless steel and are not susceptible.

2. In 2010, during disassembly of a fire protection deluge valve in Unit 3 to repair what was reported as 'hard to turn' it was discovered the valve seat and stem were corroded. The valve was repaired.

3. In 2011, during the replacement of a section of failed piping on the 3T9 Instrument Air dryer north tower it was noted that the inside of the existing piping had a large buildup of corrosion and rust. The dryer tower was scheduled for replacement.

4. In 2012, during inspection of the Unit 4 steam supply check valve for the C auxiliary feed water pump, cracks were found in the seat and valve body of the carbon steel valve. The valve was repaired.

5. In 2013, while inspecting a Unit 4 bleeder trip valve in the main turbine system, maintenance technicians found some pits, about 1/4-inch wide in the valve body (near the seat) that appeared to be casting defects and this prompted a nondestructive evaluation for cause. Adequate wall thickness margin was determined.

6. In 2017, biological fouling of both Unit 3 and Unit 4 component cooling water heat exchangers (raw water side) prompted addition of chemicals to the cooling canal water as an interim control measure while an Operating Margin Program team considers long term action.

Action requests also demonstrated plant staff appreciation for the value of one-time inspections that were initiated for cause:

1. In 2010, repeated chemical contaminants in the site condensate storage tank (CST) after windy storms prompted the plant staff to suspect corrosion in the pathway from atmosphere to the CST through the vent tanks (and the tank roof) and called for an internal inspection.

2. In 2012, during modification of the turbine cross under piping, erosion of the elbows was noted by visual inspection prompting an inspection and evaluation of the piping prior to completing the modification.

3. The PTN steam generator transition cones were cut in the middle to replace the bottom part of each steam generator. The resulting new circumferential weld in each steam generator is a field weld, as opposed to the upper and lower transition cone welds which were performed in a controlled manufacturing facility. To help address the effectiveness of the Water Chemistry program, the PTN One-Time Inspection AMP will perform an inspection on the new transition cone weld of the steam generators. This inspection will be a volumetric inspection consistent with the techniques currently in place (used for the original transition cone welds).

During the 10-year period prior to the SPEO, one-time inspections will be accomplished at PTN using ASME NDE techniques to identify possible aging effects. ASME code techniques in the ASME Section XI ISI Program have proven to be effective in detecting aging effects prior to loss of intended function. Review of PTN site-specific operating experience associated with the ISI Program has not revealed any ISI program adequacy issues or implementation issues with the PTN ASME Section XI ISI Program. The same NDE techniques used in the ASME Section XI ISI Program will be used in the PTN One-Time Inspection AMP. Using ASME code NDE techniques will be effective in identifying aging effects if present.

Based on reviews of available operating experience and the strength of ASME code NDE techniques, the PTN One-Time Inspection AMP provides reasonable assurance that the program will be effective in identifying aging effects: loss of material, cracking, or reduction of heat transfer aging effects in the systems and components included in the One-Time Inspection AMP in the 10-year period prior to the SPEO. Industry and site-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The PTN One-Time Inspection AMP will provide reasonable assurance that the PTN Fuel Oil Chemistry AMP (Section B.2.3.18), Lubricating Oil Analysis AMP (Section B.2.3.26), and Water Chemistry AMP (Section B.2.3.2) will be effective in managing the effects of aging so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.21 Selective Leaching

Program Description

The PTN Selective Leaching AMP is a new condition monitoring program that includes inspection for components that may be susceptible to loss of material due to selective leaching by demonstrating the absence of selective leaching (dealloying) of materials. Materials that may be susceptible include gray cast iron, ductile iron, and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to a raw water, treated water, waste water, lubricating oil, or soil environment.

Depending on environment, the PTN Selective Leaching AMP includes either one-time inspections or opportunistic and periodic visual inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques (e.g., chipping, scraping). Destructive examinations of components to determine the presence of and depth of dealloying through-wall thickness are also conducted. These techniques can determine whether loss of material due to selective leaching is occurring and whether selective leaching will affect the ability of the components to perform their intended function for the SPEO.

To date, PTN site-specific OE has not revealed selective leaching in components exposed to treated water. Those components are only subject to a one-time inspection unless that inspection identifies selective leaching. For components in other environments, periodic inspections will be performed every 10 years and opportunistic inspections will be performed when possible. The populations requiring examination and their type of required inspections for PTN 3 and 4 are:

- Copper alloy > 8 percent aluminum exposed to raw water (Periodic and Opportunistic)
- Copper alloy > 8 percent aluminum exposed to treated water (One-Time)
- Copper alloy > 8 percent aluminum exposed to soil (Periodic and Opportunistic)
- Copper alloy > 15 percent zinc and raw water (Periodic and Opportunistic)
- Copper alloy > 15 percent zinc and treated water (One-Time)
- Copper alloy > 15 percent zinc exposed to soil (Periodic and Opportunistic)
- Gray cast iron exposed to raw water (Periodic and Opportunistic)
- Gray cast iron exposed to treated water (One-Time)
- Gray cast iron and waste water (Periodic and Opportunistic)
- Gray cast iron and lubricating oil (Periodic and Opportunistic)
- Gray cast iron exposed to soil (Periodic and Opportunistic)
- Ductile iron exposed to raw water (Periodic and Opportunistic)

Each of the one-time and periodic inspections for these populations at each unit comprises a 3 percent sample or a maximum of 10 components. Gray cast iron and ductile iron components will be visually and mechanically inspected, the rest will be visually inspected. In addition, for gray cast iron exposed to raw water and ductile iron exposed to raw water (i.e., the only populations having 35 or more components), two destructive examinations will be performed for each material and environment population in each 10-year inspection interval at each unit. For each population with less than 35 susceptible components, one destructive examination will be performed.

The inspections associated with this AMP will cover internal and external surfaces susceptible to selective leaching; however, those components with interior coatings that protect against selective leaching will have their internal surfaces monitored under the PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.29).

Initial inspections will be performed no earlier than 10 years prior to and no later than six months prior to entering the SPEO, or no later than the last RFO prior to the SPEO. Corresponding dates are as follows: Unit 3: 7/19/2022 - 1/19/2032 and Unit 4: 4/10/2023 - 10/10/2032.

Accessible surfaces will be visually inspected, and inspection of accessible surfaces of gray cast iron and ductile iron will be augmented with the mechanical examination techniques. The visual inspections include monitoring of visual appearances, such as color, porosity, and abnormal surface conditions.

The selective leaching process involves the preferential removal of one of the alloying components from the material. Dezincification (loss of zinc from brass) and graphitization or graphitic corrosion (removal of iron from gray cast iron and ductile iron) are examples of such a process. Susceptible materials exposed to high operating temperatures, stagnant-flow conditions, and a corrosive environment are subject to selective leaching. A dealloyed component often retains its shape and may appear to be unaffected; however, the functional cross-section of the material has been reduced. The aging effect attributed to selective leaching is loss of material because the affected volume has a permanent change in density and does not retain mechanical properties that can be credited for structural integrity.

As a preventive measure, for treated water systems, the XI.M2 Water Chemistry AMP is used to mitigate the effects of selective leaching. In addition, coatings are also applied to some components in the ICW system.

The inspection acceptance criteria are as follows:

a. For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide.

b. For gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations.

c. The presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal.

d. The components meet system design requirements such as minimum wall thickness, when extended to the end of the SPEO.

When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the SPEO, additional inspections are performed if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of additional inspections is equal to the number of failed inspections for each material and environment population, with a minimum of five additional visual and mechanical inspections when visual and mechanical inspections did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria.

If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next RFO interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since PTN is a multi-unit site, the additional inspections include inspections at both Units 3 and 4 when the two units have the same material, environment, and aging effect combination.

The PTN Selective Leaching AMP will have a new governing and inspection procedure consistent with NUREG-2191, Section XI.M33.

NUREG-2191 Consistency

The PTN Selective Leaching AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M33, “Selective Leaching.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

As summarized in NUREG-2191, industry OE shows that selective leaching has been detected in components constructed from gray cast iron, ductile iron, brass, and aluminum bronze. PTN evaluates industry OE items for applicability per the FPL Fleet OE Program and takes corrective actions when necessary. For example, PTN reviewed a licensee's report in 2011 of selective leaching found during inspection of external surfaces of underground gray cast iron fire protection system piping. PTN engineering confirmed that comparable piping at PTN was not gray cast iron and noted that excavated fire main piping at PTN had been observed to be in excellent condition.

As noted in the Program Description above, the PTN Selective Leaching AMP is a new program at PTN to be implemented prior to the SPEO. Therefore, there is no existing site-specific OE to validate the effectiveness of this program at PTN; however, the following summary of site-specific OE (which included reviews of corrective actions, audits, NRC inspections, and program health reports) is relevant to inspection, evaluation, and corrective action methods that will be used by the PTN Selective Leaching AMP.

1. A one-time inspection of the "A" AFW turbine governor controller oil cooler was performed in March 2011. Both end caps were found to be in good condition. Results of spectral analysis indicated that the end caps are high-leaded bronze (i.e., not cast iron). The zinc content was found to be well below 15 percent by weight; therefore, the end caps are not susceptible to selective leaching (dezincification).

2. A one-time inspection of the "C" AFW pump turbine oil cooler was performed in February 2012. This cooler, whose materials of construction include gray cast iron, had been in service for 39 years. After sand blasting, significant loss of metal was found mostly in the divider plates. Black surface color and porous surface texture was observed, indicating that graphitic corrosion (selective leaching) had occurred. Based on results of this inspection, the "C" AFW pump turbine lube oil cooler was replaced in February 2012 and the "B" AFW pump turbine lube oil cooler was replaced in September 2012. An engineering evaluation determined that further inspection or replacement of the "A" AFW pump turbine lube oil cooler was not warranted because it had been replaced in March 1999.

3. Remote video crawler inspection in a buried portion of the Unit 3 circulating water system "B" header (performed in April 2012 at PTN as part of the industry-wide buried piping integrity initiative established under NEI 09-14) revealed an unanticipated degradation mechanism of spool pieces in transition piping downstream of the circulating water pump discharge valves. Between 2013 and 2017, subsequent activities determined a vulnerability to graphitic corrosion (selective leaching) for all eight such spool pieces installed at PTN caused by uncoated gray cast iron surfaces exposed to continuous flow of salt water. Using visual inspection data informed by depth measurements at representative sample locations and measurement of wall thickness (UT) of the spool pieces, engineering evaluations during outages determined the acceptability for

continued operation of the spool pieces pending permanent repairs. To terminate degradation due to selective leaching, protective coatings were applied to both spool pieces in the Unit 3 "A" circulating water header in November 2015. The remaining six spools are scheduled to be inspected and repaired in conjunction with circulating water pump motor replacements.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12. This process provides reasonable assurance that the PTN Selective Leaching AMP is informed and enhanced, if necessary, by relevant OE.

Conclusion

The PTN Selective Leaching AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.22 ASME Code Class 1 Small-Bore Piping

Program Description

The PTN ASME Code Class 1 Small-Bore Piping AMP, formerly the PTN Small Bore Class 1 Piping Inspection Program, is an existing condition monitoring program for detecting cracking in small-bore, ASME Code Class 1 piping. This AMP augments the ISI specified by ASME Code, Section XI (Reference B.3.122), for certain ASME Code Class 1 piping that is less than 4 inches nominal pipe size (NPS) and greater than or equal to 1 inch NPS, and manages the effects of SCC and cracking due to thermal or vibratory fatigue loading. This AMP inspects for ASME Code Class 1 small-bore piping locations that are susceptible to cracking, and inspects pipes, fittings, branch connections, and all full and partial penetration (socket) welds. This AMP also includes measures to verify that degradation is not occurring, thereby confirming that there is no need to manage age-related degradation.

Industry OE demonstrates that welds in ASME Code Class 1 small-bore piping are susceptible to SCC and cracking due to thermal or vibratory fatigue loading. Such cracking is frequently initiated from the inside diameter of the piping; therefore, volumetric examinations are needed to detect cracks. However, ASME Code, Section XI, generally does not call for volumetric examinations of this class and size of piping. Therefore, this AMP supplements the ASME Code Section XI examinations with volumetric examinations, or alternatively, destructive examinations, to detect cracks that may originate from the inside diameter of butt welds, socket welds, and their base metal materials. The examination schedule and extent is based on site-specific OE and whether actions have been implemented that would successfully mitigate the causes of any past cracking.

A one-time inspection, intended to detect potential cracking resulting from thermal and mechanical loading, vibration, or intergranular stress corrosion of full penetration welds, will be performed by volumetric examination on the ASME Code Class 1 small-bore piping. A one-time inspection to detect cracking in welds and base metal materials will be performed by either volumetric or destructive examination. These inspections will provide additional assurance that either aging of small-bore ASME Code Class 1 piping is not occurring or the aging is insignificant. Should evidence of cracking be revealed by the one-time inspections, a periodic inspection plan will be implemented in accordance with NUREG-2191, Table XI.M35-1.

A volumetric inspection of a sample, as specified in NUREG-2191, Table XI.M35-1, of small bore Class 1 piping and nozzles will be performed to determine if cracking is an aging effect requiring management during the SPEO. If an acceptable volumetric technique cannot be used to perform a volumetric inspection, a destructive examination will be performed. For each socket weld that is destructively examined credit may be taken as being equivalent to volumetrically examining two socket welds. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions will be established. The inspection will be performed prior to the SPEO for PTN Units 3 and 4.

Per NUREG-2191, Table XI.M35-1, PTN is a Category A plant because it has no history of age-related cracking. Per Category A, the inspection will be a one-time inspection with a sample size of at least 3 percent, up to a maximum of 10 welds, of each weld type, for each operating unit using a methodology to select the most susceptible and risk-significant welds. For socket welds, destructive examination may be performed in lieu of volumetric examinations. Because more information can be obtained from a destructive examination than from nondestructive examination, credit will be taken for each weld destructively examined equivalent to having volumetrically examined two welds.

This one-time inspection is designed to provide assurance that aging of ASME Code Class 1 small-bore piping is not occurring, or that the effects of aging are effectively managed. The one-time inspection to detect cracking in socket welds will be either a volumetric or destructive examination. The inspection to detect cracking resulting from thermal and mechanical loading, vibration, or intergranular stress corrosion of full penetration welds will be a volumetric examination. Volumetric examination will be performed using demonstrated techniques from the ASME Code that are capable of detecting the aging effects in the examination volume of interest. The inspection will be performed at a sufficient number of locations to ensure an adequate sample. This number, or sample size, is based on susceptibility, accessibility, dose considerations, OE, and limiting locations of the total population of ASME Code Class 1 small-bore piping inspections. Evaluation of the inspection results may indicate the need for additional or periodic examinations in accordance with NUREG-2191, Table XI.M35-1.

Table B-6
Weld Sampling at PTN Unit 3

Weld Type	**Total Number**	**3 percent**	**Sample Size (Max 10 Welds Each Type)**		
			Volumetric		**Destructive**
Socket	468	14	10	OR	5
Full penetration	113	4	4		

Table B-7
Weld Sampling at PTN Unit 4

Weld Type	**Total Number**	**3 percent**	**Sample Size (Max 10 Welds Each Type)**		
			Volumetric		**Destructive**
Socket	498	15	10	OR	5
Full penetration	125	4	4		

Since PTN is a Category A plant, this is a one-time inspection to determine whether cracking in ASME Code Class 1 small-bore piping resulting from stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence is an issue. Evaluation of the inspection results may indicate the need for additional or periodic examinations, which would result in a change of category in accordance with Table XI.M35-1. If a component containing flaws or relevant conditions is accepted for continued service by analytical evaluation, then it is subsequently reexamined to meet the intent of ASME Code, Section XI, Sub-article IWB-2420. Examination results then are evaluated in accordance ASME Code, Section XI, Paragraph IWB-3132. The corrective actions include examinations of additional ASME Code Class 1 small-bore piping welds to meet the intent of ASME Code, Section XI, Sub-article IWB-2430. Additionally, periodic examinations are implemented in accordance with the schedule specified in Category C.

NUREG-2191 Consistency

The PTN ASME Code Class 1 Small-Bore Piping AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M35, “ASME Code Class 1 Small-Bore Piping.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN ASME Code Class 1 Small-Bore Piping AMP will be enhanced as follows, for alignment with NUREG-2191. This AMP is to be implemented and its inspections are to be completed no earlier than six years prior to the SPEO and no later than six months prior to the SPEO, or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria 7. Corrective Actions	Create a new procedure to do the following: • Perform the new one-time inspections of small-bore piping using the program methods, frequencies, and acceptance criteria. • Evaluate the results to determine if additional or periodic examinations are required. • Perform any required additional inspections.

Operating Experience

Industry Operating Experience

Industry operating experience indicates that cracking due to SCC and cracking due to thermal or vibratory fatigue loading in small-bore Class 1 piping can cause structural degradation, including the loss of pressure boundary function, to susceptible small-bore Class 1 piping components in nuclear power plants.

On February 16, 2015, the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) issued letter MRP-2015-005 (Reference B.3.110) to PWR plant site vice presidents. The notification was in response to recent operating experience in piping and components potentially exposed to thermal stratification fatigue. The letter stated that since 2013, there were 10 relevant cracking events, eight of which had thermal fatigue as the primary causal factor. In response to this notification, on May 28, 2015, the EPRI MRP issued letter MRP-2015-019 (Reference B.3.111) regarding implementation of NEI 03-08 "Needed and Good Practice Interim Guidance Requirements for Management of Thermal Fatigue." The interim guidance provided additional examination requirements in the form of two good practices and eight needed elements

In response to letter MRP-2015-019, FPL requested that Structural Integrity Associates (SIA) perform a review of the PTN MRP-146 (Reference B.3.109) and MRP-192 (Reference B.3.112) thermal fatigue program documents to identify specific recommendations to ensure compliance with the updated interim guidance. Based on a comparison of the PTN thermal fatigue management programs and the new guidance, recommendations (if necessary) were provided for each element.

SIA concluded that the PTN thermal fatigue program documents are in full compliance with all good practices and needed thermal fatigue requirements specified by the EPRI MRP-146 program and will be in compliance with the EPRI MRP-192 program after implementing the following two recommendations:

- PTN should obtain RHR heat exchanger inlet and outlet temperatures to confirm the actual temperature difference across the heat exchanger during plant heatup. This action has been entered into the PTN CAP and actions are in place to monitor these temperatures for each RHR heat exchanger during next three refueling outages on each unit, commencing with the Unit 4 Fall 2017 outage.

- CAP documentation should be revised to document that the Unit 4 safety injection line inspection volume is < 90 percent coverage due to current piping geometry. This action was entered into the PTN CAP for document revision, and the action is complete.

Site-Specific Operating Experience

The following review of site-specific operating experience prior to the first PEO provides objective evidence that the ASME Code Class 1 Small-Bore Piping AMP effectively manages aging effects so that the intended functions of components within the scope of the ASME Code Class 1 Small-Bore Piping AMP will be maintained during the SPEO.

1. In 2012, destructive examination of Class 1 small bore piping within the scope of the ASME Code Class 1 Small-Bore Piping AMP was performed on Unit 3. The Unit 3 inspection scope consisted of an approximate 18-inch long section of two-inch piping from the SI system containing a total of five socket welds (two on an elbow and three on a tee). Visual inspection, sectioning, and metallographic analysis were performed on each of the socket welds. Overall, features such as the gaps, lack of fusion and porosity noted in the welds were considered normal for fillet welds. No signs of actively growing or operationally related cracks were noted in any of the weld samples.

   In addition, a volumetric (UT) examination was performed on six 3-inch Class 1 full penetration butt welds. No recordable indications were identified.

2. In 2013, destructive examination of Class 1 small bore piping within the scope of the ASME Code Class 1 Small-Bore Piping AMP was performed for PTN Unit 4. The Unit 4 inspection scope included five two-inch elbows (three from the CVCS and two from the SI system) containing a total of seven socket welds. Visual inspection, sectioning, and metallographic analysis were performed on each of the socket welds. Overall, features such as the gaps, lack of fusion and porosity noted in the welds were considered normal for fillet welds. No signs of actively growing or operationally related cracks were noted in any of the weld samples.

   In addition, a volumetric (UT) examination was performed on five 3-inch Class 1 full penetration butt welds. No recordable indications were identified.

3. In July of 2012, a post-approval license renewal inspection was performed by NRC prior to the period of extended operation. No findings were identified from the inspection; however, one observation was noted which identified a potential inadequacy regarding the small-bore Class 1 piping inspection sample scope for Unit 3. The inspectors were concerned that the single location of similar weld types selected for destructive examination did not constitute a representative sample on which to base a determination that no aging effects were present. The observation was captured in the CAP and for the scope of the subsequent Unit 4 inspections, the samples chosen were all from different welds that were exposed to various pressure-temperature environments and consistent with the intent of the program. No additional actions were deemed necessary.

The site-specific OE for ASME Code Class 1 Small-bore Piping indicates that no age-related cracking has been identified, thus PTN remains a Category A plant per NUREG-2191, Table XI.M35-1. The OE relative to the ASME Code Class 1 Small-Bore Piping AMP illustrates that the existing program will effectively utilize industry and site-specific OE to properly select small-bore piping locations for inspection. The CAP will be effective in evaluating the inspection results to determine the need for additional or periodic examinations, if required. Therefore, there is confidence that continued implementation of the ASME Code Class 1 Small-Bore Piping Fatigue Monitoring AMP will effectively identify age-related degradation prior to failure or loss of intended function during the SPEO.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN ASME Code Class 1 Small-Bore Piping AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.23 External Surfaces Monitoring of Mechanical Components

Program Description

The PTN External Surfaces Monitoring of Mechanical Components AMP is an existing AMP that was formerly a portion of the PTN Systems and Structures Monitoring Program. The PTN External Surfaces Monitoring of Mechanical Components AMP is a condition monitoring program that manages loss of material, cracking, hardening or loss of strength (of elastomeric components), loss of preload for ducting closure bolting, reduction of heat transfer due to fouling (air to fluid heat exchangers), and reduction of thermal insulation resistance due to moisture intrusion. This AMP also inspects the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces.

Components that are within the scope of both the PTN External Surfaces Monitoring of Mechanical Components AMP and the PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP may have these inspections performed in lieu of wall thickness measurements. Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. When required by the ASME Code, inspections are conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings. The inspections are capable of detecting age-related degradation and, with the exception of examinations to detect cracking in stainless steel or aluminum components, are 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 refueling outages (e.g., high dose areas). Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components’ intended functions are maintained.

Periodic visual inspections or surface examinations are conducted on stainless steel and aluminum components to manage cracking every 10 years during SPEO. Surface examinations or VT-1 examinations are conducted on 20 percent of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections.

Aging effects associated with below grade components that are accessible during normal operations or RFOs, for which access is not restricted, are managed by the PTN External Surfaces Monitoring of Mechanical Components AMP. For certain materials, such as flexible polymers, physical manipulation to detect hardening or loss of strength or reduction in impact strength is used to augment the visual examinations conducted under this AMP.

These visual inspections also inspect for external corrosion under insulation. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are also periodically inspected at a minimum of every 10 years during the SPEO. Sample inspections are conducted of each material type and environment where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin.

Alternative methods for detecting moisture/corrosion inside piping insulation are used by the PTN External Surfaces Monitoring of Mechanical Components AMP. In addition to visual inspections, these methods can help identify corrosion in the insulated piping and jacketing. These methods can be used for inspecting piping jacketing that are not installed in accordance with site-specific procedures (i.e., no minimum overlap, wrong location of seams, etc.). Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with site-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions.

The PTN External Surfaces Monitoring of Mechanical Components AMP also visually inspects the external surfaces of heat exchanger surfaces exposed to air (e.g., ventilation heat exchanger fins) for evidence of reduction of heat transfer due to fouling.

For situations where the internal (inaccessible) and external (accessible) surface environments are similar, such that the external (accessible) surface condition is representative of the internal (inaccessible) surface condition, then visual inspection of the accessible surfaces/components is performed. The PTN External Surfaces Monitoring of Mechanical Components AMP procedures provide the basis to establish that the external and internal surface condition and environment are sufficiently similar. These inspections provide reasonable assurance that the following effects are managed:

a. Loss of material/cracking of internal surfaces for metallic components.
b. Loss of material/cracking of internal surfaces for polymeric components.
c. Hardening or loss of strength of internal surfaces for elastomeric components.

Depending on the material, components may be coated to mitigate corrosion by protecting the external surface of the component from environmental exposure. To minimize corrosion, external surfaces of carbon steel valves, piping and fittings, stainless steel piping (less than 8 inches, Schedule 10) welds, cast iron equipment, and surfaces of steel structures and supports are coated per approved plant procedures and in accordance with approved design documents, which include drawings and specifications. Inspections to verify the integrity of the insulation lagging/jacketing are performed per the PTN External Surfaces Monitoring of Mechanical Components AMP procedures.

The PTN External Surfaces Monitoring of Mechanical Components AMP uses periodic plant system inspections and walkdowns to monitor for material degradation, coating deterioration, accumulation of debris (including fouling), loss of material, cracking, and leakage. The PTN External Surfaces Monitoring of Mechanical Components AMP inspects components such as piping, piping components, ducting, seals, insulation jacketing, and air-side heat exchangers. Examples of inspection parameters monitored for metallic components include:

- Corrosion and surface imperfections
- Cracking
- Loss of material / wall thickness
- Flaking (and/or oxide-coated surfaces)
- Corrosion (stains) on thermal insulation
- Protective coating degradation (Cracking, flaking, or blistering)
- Change in material properties (identified by leakage/defect-focused visual inspections of external surfaces)
- Fouling of heat exchanger tube surfaces (reduction of heat transfer)

For sampling-based inspections, statistical tools are routinely utilized where most appropriate for data analysis, and when combined with system or component data in spreadsheets, insights regarding increased variance, statistically significant trends, failure mode analysis are realized. Usage of these statistical tools confirms that the sampling bases will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation.

The PTN External Surfaces Monitoring of Mechanical Components AMP procedures define acceptance criteria that are utilized during inspection walkdowns to identify deficiencies in the in-scope component groups. PTN External Surfaces Monitoring of Mechanical Components AMP procedures require corrective actions be initiated for deficiencies identified during the walkdowns to ensure that loss of component intended functions does not occur. The PTN External Surfaces Monitoring of Mechanical Components AMP procedures utilize guidance from the EPRI Technical Report TR-1007933 (Reference B.3.89), “Aging Assessment Field Guide,” for identifying metal degradation and corrosion mechanisms. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection and the degradation is a valid indication or trend, then a CR is issued to perform an assessment and document the appropriate actions and recommendations; which may include the adjustment of inspection frequencies. When a CR is generated, the associated corrective action is documented in accordance with the PTN CAP and the CRs require the determination of probable cause and actions to prevent recurrence for significant conditions adverse to quality.

NUREG-2191 Consistency

The PTN External Surfaces Monitoring of Mechanical Components AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M36, “External Surfaces Monitoring of Mechanical Components.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN External Surfaces Monitoring of Mechanical Components AMP will be enhanced as follows, for alignment with NUREG-2191. There are no new inspections required for SLR; however, existing inspection frequencies may change. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise PTN External Surfaces Monitoring of Mechanical Components AMP procedures to perform inspections for monitoring aging effects for elastomers and flexible polymeric components, including manual or physical manipulations of the material, with a sample size for manipulation of at least 10 percent of the available surface area. The inspection parameters for elastomers and polymers shall include the following: • Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”). • Loss of thickness. • Discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation). • Exposure of internal reinforcement for reinforced elastomers. • Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation. Ensure that accumulation of debris on in-scope components is monitored. Ensure that seals, insulation jacketing, and air-side heat exchangers are inspected components.
4. Detection of Aging Effects	Revise PTN External Surfaces Monitoring of Mechanical Components AMP procedures to perform inspections for monitoring aging effects for elastomers and flexible polymeric components, including manual or physical manipulations of the material, with a sample size for manipulation of at least 10 percent of the available surface area. The inspection parameters for elastomers and polymers shall include the following:

Element Affected	Enhancement
4. Detection of Aging Effects (continued)	• Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”). • Loss of thickness. • Discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation). • Exposure of internal reinforcement for reinforced elastomers. • Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation. Inspections are to be performed by personnel qualified in accordance with site procedures and programs to perform the specified task, and when required by the ASME Code, inspections are conducted in accordance with the applicable code requirements. Perform inspections for loss of material, cracking, changes in material properties, hardening or loss of strength (of elastomeric components), reduced thermal insulation resistance, loss of preload for ducting closure bolting, and reduction of heat transfer due to fouling at an inspection frequency of every RFO for all in-scope non-stainless steel and non-aluminum components, which include metallic, polymeric, insulation jacketing (insulation when not jacketed). Non-ASME Code inspections and tests should include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings. Surfaces that are not readily visible during plant operations and RFOs should be inspected when they are made accessible and at such intervals that would ensure the components’ intended functions are maintained. Surface examinations, or VT-1 examinations, are conducted on 20 percent of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. The provisions of GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” to conduct inspections in a more severe environment and combination of air environments may be incorporated for these inspections. Alternative methods for detecting moisture inside piping insulation (thermography, neutron backscatter devices, and moisture meters) are to be used for inspecting piping jacketing that is not installed in accordance with site-specific procedures (i.e., no minimum overlap, wrong location of seams, etc.).

Element Affected	Enhancement
4. Detection of Aging Effects (continued)	Include the following information: • Component surfaces that are insulated and exposed to condensation (because the in-scope component is operated below the dew point), and insulated outdoor components, are periodically inspected every 10 years during the SPEO. • For all outdoor components and any indoor components exposed to condensation (because the in-scope component is operated below the dew point), inspections are conducted of each material type (e.g., steel, stainless steel, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. Inspections for cracking due to SCC in aluminum components need not be conducted if it has been determined that SCC is not an applicable aging effect.
6. Acceptance Criteria	Include guidance from EPRI TR-1007933 (Reference B.3.89), “Aging Assessment Field Guide” and TR-1009743 (Reference B.3.90), “Aging Identification and Assessment Checklist” on the evaluation of materials and criteria for their acceptance when performing visual/tactile inspections.

Element Affected	Enhancement
7. Corrective Actions	Include information for the additional inspections that are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. To ensure that the sampling-based inspections detect cracking in aluminum and stainless steel components, additional inspections should be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site's corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria. The additional inspections are completed within the interval (i.e., 5-year inspection interval) in which the original inspection was conducted. If subsequent inspections do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis are conducted to determine the further extent of inspections. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since PTN is a multi-unit site, the additional inspections include inspections at all of the units with the same material, environment, and aging effect combination. Revise the CAP procedure to point to appropriate External Surfaces Monitoring of Mechanical Components AMP procedure for corrective actions.

Operating Experience

Industry Operating Experience

PTN established the external surfaces inspections via system inspections and walkdowns based on the programs in effect at many utilities since the mid 1990's in support of the Maintenance Rule (10 CFR 50.65). Additional guidance published by EPRI in the early 2000s including an aging identification and assessment checklist and an aging assessment field guide were incorporated into PTN system and program engineer walkdown procedures. These inspections have proven to be effective in maintaining the material condition of plant systems. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) at PTN are consistent with industry practice.

Site-Specific Operating Experience

As part of the NRC inspection performed prior to the PEO for original license renewal, the NRC verified that the Systems and Structures Monitoring examinations performed during the spring 2012 outage were implemented as stated in the commitment. Additionally, the NRC directly observed the VT-3 examination of the 58-foot level of containment (which included all accessible structures and containment surfaces) to verify that essential attributes, such as calibration and disposition of indications, were performed in accordance with the license renewal commitment.

The following examples of OE provide objective evidence that the PTN External Surfaces Monitoring of Mechanical Components AMP will be effective in ensuring that intended functions are maintained consistent with the CLB for the SPEO.

1. In April 2015, a section (approximately 10 to 15 feet in length) of an EDG room ventilation duct over the top of the EDG was found to be corroded due to the presence of moisture. The issue was documented in the CAP for disposition. The corrosion did not penetrate the ventilation ducting and therefore did not impact air flow. In addition, the ducting is associated with a nonsafety-related exhaust fan and does not impact the EDG operability. Further actions were made to repair and refinish the ducting through the maintenance work order (WO) process and the CAP item was closed.

2. In August 2015, the station performed the monthly 10-foot Radioactive Piping integrity checks and a search for CCW piping leaks. During the check, a portion of the Unit 3 and Unit 4 CCW piping located on the east side of the 10-foot Radioactive Pipeway was discovered to be degraded due to visible external corrosion. This degradation was previously investigated under another CAP item initiated in 2014. This previous CAP item required that non-destructive examination (NDE) be performed utilizing ultrasonic testing (UT) to determine that the current pipe wall thickness exceeded required minimum thicknesses. Although there was no observed leakage, some areas, especially on the Unit 3 CCW piping, were evaluated. Plant engineering performed a condition evaluation and determined that the extent of corrosion did not compromise the ability of the piping to perform its function. The cause of the corrosion was attributed to leaking piping penetration seals located above the CCW piping. In the interim, a temporary patch for the penetration seal was installed and periodic visual inspections are performed to assess piping condition until the final repair could be implemented. The required actions were performed through the WO process and the CAP item was closed.

3. In November of 2015, the auxiliary feed water piping downstream of the discharge isolation valve was unpainted and began to corrode. A subsequent engineering walkdown determined that the auxiliary feed water piping had only minor surface corrosion that did not impact equipment operability. A CAP item was created to drive cleaning and subsequent painting of the pipe surface with the minor surface corrosion. The required actions were performed through the WO process and the CAP item was closed.

4. In November of 2015, a walkdown was performed noting deteriorated coatings of CCW piping within a wall penetration downstream of a reactor coolant pump and was documented in a CAP item. This deterioration in the pipe coating was noted to be very similar to the deterioration of a similar section of pipe related to an alternate train, documented in another CAP item. This similar piping section had been inspected by UT and found to be acceptable. From similarity, the CCW piping section of interest was concluded to be operable, and additional analysis was performed to support this justification. To ensure the analysis remains valid, an existing preventive maintenance (PM) activity was identified to periodically inspect CCW piping lines, including the pipes of

interest. The required re coating activities have been planned in a WO and tracked under another CAP item.

5. In January of 2016, a section of CCW pipe near the spent fuel pool heat exchanger was found to be missing paint and corroded. As a result, the issue was documented in the CAP. The CAP item concluded that the surface corrosion is minor and that sufficient pipe thickness is present. Initially, a bi-monthly monitoring requirement had been established. As a result of the first inspection, this monitoring requirement was extended to six months and is being tracked under the CAP.

6. In April of 2016, the inside containment CCW piping for a reactor coolant pump, was inspected under the fuel transfer tunnel and the coatings in the inaccessible section were noted to be degraded (blistered, chipping, flaking). As a result of the damage to the coating and inaccessibility to perform UT, the condition of the carbon steel piping under the coatings was unknown and a CAP item was generated. Based on a review of previous evaluations regarding this corrosion, there is substantial margin over and above the minimum pipe thickness to ensure CCW system operability. An updated analysis was performed in the CAP item to justify that substantial margin in the minimum pipe thickness is still present such that the CCW system is operable. As a long term solution, additional plans are being implemented through the CAP including measurement of the actual wall thickness and documentation of the results.

The above examples provide objective evidence that the PTN External Surfaces Monitoring of Mechanical Components AMP is capable of both detecting and trending the aging effects of surface corrosion on mechanical components. A review of the OE examples showed that, where age-related degradation has been identified, the appropriate measures have been taken or specified to prevent loss of intended function. The CAP is constructively used to take corrective actions prior to loss of component intended function. Conditions identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found.

As stated in Section B.1.1, the Systems and Structures Monitoring Program, credited for the PEO, was found to be ineffective in the December 2017 AMP effectiveness review. At PTN, the Systems and Structures Monitoring AMP is treated as two separate AMPs. The Systems sub-part of the AMP will be discussed here, since it is most associated with the PTN External Surfaces Monitoring of Mechanical Components AMP which will be credited for the SPEO. The Systems sub-part of the AMP failed Element 1, Scope of Program, Element 4, Detection of Aging Effects, and Element 7, Corrective Actions. Failed elements were due to the deficiencies listed below.

a. An engineering change package removed the Unit 4 main steam isolation valve (MSIV) instrument air accumulator tanks from the plant and the program scope was not updated. However, this did not result in ineffective aging management as the tanks are no longer installed at the plant. The program was revised in December 2017 to remove the tanks from scope.

b. The intended function of CCW piping within the scope of the systems and structures monitoring AMP was found to be degraded (paint flaking and corrosion at a support) prior to the detection of aging. An operability evaluation was performed that determined the piping was operable, but degraded.

c. Certain LR inspections such as the excess letdown heat exchanger and CRDM cooler inspections within the scope of the Systems and Structures Monitoring Program had exceeded their required frequency. These LR inspections were completed in December of 2017. An LR walkdown matrix was added to the program procedure to ensure all LR walkdowns are completed on time.

d. Identified corrosion items were not always documented in the LR sections of the shutdown heat removal walkdowns. The corrosion areas were added to the corrective action process for evaluation and repair.

e. A cause evaluation had not been completed for the LR inspections that had exceeded their required frequency (see item c, above). The cause evaluation was completed in December of 2017.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. As described, corrective actions have been initiated and completed to resolve AMP issues regarding the identified ineffectiveness of the Systems and Structures Monitoring AMP. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN External Surfaces Monitoring of Mechanical Components AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.24 Flux Thimble Tube Inspection

Program Description

The PTN Flux Thimble Tube Inspection AMP, previously the PTN Thimble Tube Inspection Program, is an existing condition monitoring program used to inspect for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. This AMP manages the aging effect of loss of material due to fretting wear.

The flux thimble tube inspection associated with this AMP encompasses all of the flux thimble tubes that form part of the RCS pressure boundary. This AMP monitors flux thimble tube wall thickness to detect loss of material from the flux thimble tubes during the SPEO. The flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. Periodic bobbin coil eddy current testing (ECT) is used to monitor for loss of material and wear of the flux thimble tubes during the SPEO. This inspection AMP implements the recommendations of NRC Bulletin 88-09 (Reference B.3.53), "Thimble Tube Thinning in Westinghouse Reactors."

The frequency of examinations is based on site-specific wear data and wear predictions. The basic examination schedule was developed by Westinghouse based on evaluation of results obtained from the 2004 and 2005 RFOs. The Westinghouse examination schedule defines examinations to be performed at least every two or three fuel cycles. Thimble tube wear rates are projected over future operating cycles and future examination intervals are determined based on the disposition of examination results and engineering evaluations that have been completed, as this is required to substantiate the decision for an alternate examination interval.

Flux thimble tube wall thickness measurements are trended and wear rates are calculated using the methodology of WCAP-12866 (Reference B.3.148), "Bottom Mounted Instrumentation Flux Thimble Wear" or PTN letter JPNS-PTN-91-5374 (Reference B.3.137), "BMI Thimble Tube Wear Evaluation." The methodology set forth in these documents includes sufficient conservatism to ensure that wall thickness acceptance criteria continue to be met during plant operation between scheduled inspections. Corrective actions are taken when trending results project that acceptance criteria would not be met prior to the next planned inspection or the end of the SPEO.

Inspection results (including wall loss) are reported using the PTN CAP and are provided to the appropriate engineering personnel who evaluate, disposition and recommend any necessary corrective actions. The evaluation must determine the need for repositioning, capping or replacing the applicable damaged thimble tubing, or may provide justification to retain the original configuration of the existing thimble tube if it remains within the acceptance criteria. A maximum depth of 80 percent through-wall wear with a maximum scar length of 5.0 inches was established as the maximum acceptable through-wall wear, based on WCAP-12866. A more conservative depth of 70 percent through-wall wear is applied at PTN to ensure that the integrity of the RCS pressure boundary is maintained. This conservative depth includes allowances for instrument uncertainty and other inaccuracies.

NUREG-2191 Consistency

The PTN Flux Thimble Tube Inspection AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M37, “Flux Thimble Tube Inspection.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Flux Thimble Tube Inspection AMP will be enhanced as follows, for alignment with NUREG-2191. There are no new inspections required for SLR; however, existing inspection frequencies may change. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise the governing AMP procedure to specify the interval between inspections be established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection.
7. Corrective Actions	Revise the governing AMP procedure to state the following: Flux thimble tubes that cannot be inspected over the tube length, that are subject to wear due to restriction or other defects, and that cannot be shown by analysis to be satisfactory for continued service are removed from service to ensure the integrity of the RCS pressure boundary.

Operating Experience

Industry Operating Experience

Bottom-mounted instrumentation flux thimble tubing thinning caused by flow induced vibration was first reported in 1981 in three thimble tubes at the Salem plant. Subsequent inspections at the Salem plant and other plants identified additional worn flux thimble tubing, some with significant wall loss. In 1987, the NRC issued Information Notice 87-44, "Thimble Tube Thinning in Westinghouse Reactors." In July of 1988, the NRC issued Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." This bulletin requested operators to establish a monitoring program to monitor thimble tube performance.

In response, PTN performed ECT of the thimble tubes in both units. Unit 4 flux thimble tubes were tested in 1988 and 1990, and Unit 3 flux thimble tubes were tested in 1990 and 1992. In 1991, a PTN engineering evaluation based on updated Westinghouse Owners Group wear rate calculations was used to establish a thimble tube inspection program. After the 1992 inspection, PTN reactor engineering recommended a 5- to 10-year inspection interval based on the results of the inspections and the engineering evaluation. As discussed below, this inspection interval has been adjusted to account for site-specific operating experience.

Site-Specific Operating Experience

In 2000, PTN issued an engineering evaluation to address the activities of the Thimble Tube Inspection Program that were credited as part of the license renewal process. The evaluation reiterated the inspection requirements established in response to NRC Bulletin 88-09. ECT of all of the Unit 3 and Unit 4 flux thimble tubes occurred in 2004 and 2005, respectively, to fulfill the commitment for original license renewal prior to entering the PEO. Degradation was identified in thimble tube N-05 and other thimble tubes were projected to require replacement during the PEO. As a result, the established license renewal thimble tube inspection program was converted to a periodic inspection program in order to properly manage aging. Periodic testing has continued based on the established interval of every 2 or 3 refueling cycles.

The results of the periodic tests completed for the Unit 3 flux thimble tubes (prior to and including testing in the spring of 2012) and the wall thinning projections indicated that 19 flux thimble tubes would require replacement prior to the end of the PEO. The 7 flux thimble tubes that experienced the most wear were replaced during refueling outage PT3-27 that occurred in the spring of 2014. Per evaluations documented in the CAP, only these 7 tubes required replacement at that time, with additional tubes requiring replacement within the next 4 refueling cycles. While verifying that there was a clear path for the flux map detectors, a dummy detector became lodged inside thimble tube L-11, which has now been isolated. Replacement of the 7 thimble tubes re-established the flux mapping margin to 49 out of 50 thimble tubes for Unit 3.

The results of the periodic tests completed for the Unit 4 flux thimble tubes (prior to and including testing in the spring of 2011) and the wall thinning projections indicated that 22 flux thimble tubes would require replacement prior to the end of the PEO. The 22 flux thimble tubes were replaced during the PT4 27 refueling outage that occurred in the fall of 2012. Two of the flux thimble tubes that were replaced also required replacement isolation valves and associated components. These flux thimble tubes were capped until PT4-29, which occurred in the spring of 2016, when the thimble tubes, valves and associated components were replaced, re-establishing flux mapping margin to 50 out of 50 thimble tubes for Unit 4.

The PTN Flux Thimble Tube Inspection AMP is a mature, established program. Its effectiveness has been demonstrated as a result of the July 2012 NRC post-approval site inspection (Inspection Reports 05000250/2012008 and 05000251/2012008) which was conducted prior to entering into the PEO. This post-approval site inspection identified one observation regarding the PTN Flux Thimble Tube Inspection AMP that was entered into the CAP and resolved prior to the completion of the inspection. Specifically, the observation noted that the original commitment was to perform a one-time inspection of thimble tube N-05 in Unit 3. As degradation was identified during this one-time inspection, the PTN Flux Thimble Tube Inspection was converted to a periodic inspection to adequately manage aging. The observation was addressed by revising the program scope included in the UFSAR to indicate that the program is a periodic inspection program and not a one-time inspection as noted above.

As stated in Section B.1.1, the Thimble Tube Monitoring Program, credited for the PEO, was found to be effective at managing aging in the December 2017 AMP effectiveness review. However, the program failed Element 8, Confirmation Process. The failed element was due to there being no key personnel at PTN that managed the Thimble Tube Monitoring Program. The program-required thimble tube inspections, however, had been performed as required. In December of 2017, a program owner was assigned at PTN to manage the program.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN Flux Thimble Tube Inspection AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new condition monitoring program that manages the aging effects of loss of material, cracking, erosion, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of elastomeric and polymeric materials. Some of inspections and activities within the scope of this new AMP were previously performed by the PTN Systems and Structures Monitoring Program, the PTN Periodic Surveillance and Preventive Maintenance Program, and other site-specific programs.

This AMP consists of visual inspections and, when appropriate, surface examinations, of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to potentially aggressive environments. These environments include air, air with borated water leakage, condensation, gas, diesel exhaust, fuel oil, lubricating oil, and any water-filled systems not managed by another AMP. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP.

This AMP is also used to manage internal cracking due to SCC in aluminum and stainless steel components exposed to aqueous solutions and the air environments which contain halides.

This AMP does not manage aging effects associated with items within the scope of the PTN Open Cycle Cooling Water System AMP (Section B.2.3.11), PTN Closed Treated Water Systems AMP (Section B.2.3.12), and PTN Fire Water Systems AMP (Section B.2.3.16); with the exception of elastomers and flexible polymeric components, which are managed by this AMP.

The internal inspections associated with this AMP are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the SPEO, 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 unit. The maximum of 19 components per unit for inspection is used in lieu of 25 components per unit due PTN being a 2-unit plant with sufficiently similar operating conditions at each unit (e.g., flowrate, chemistry, temperature, excursions), similar time in operation for each unit, similar water sources, and similar operating frequency.

Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP.

Inspections that are not required to be conducted in accordance with ASME Code Section XI requirements are conducted in accordance with site-specific procedures, and such inspections include inspection parameters for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Where practical, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). Where qualitative acceptance criteria are used, the criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions.

This AMP is not intended for use on components in which recurring internal corrosion is evident based on a search of site-specific OE. Following failure due to recurring internal corrosion, this AMP may be used if the failed material is replaced by one that is more corrosion resistant in the environment of interest, or corrective actions have been taken to prevent recurrence of the recurring internal corrosion. Based on site-specific OE searches, no evidence of recurring internal corrosion of components has been noted.

The PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP requires the creation of a new governing procedure in accordance with NUREG-2191, Section XI.M38 to monitor for and manage the aging effects associated with the internal surfaces of the in-scope miscellaneous piping, piping components, ducting, heat exchanger components, and other components. This AMP will be implemented no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

Industry OE was searched for applicability to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. No specific OE was found that was directly applicable to the new AMP.

<u>Site-Specific Operating Experience</u>

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new program for PTN to be implemented prior to the SPEO. Therefore, there is no existing program-specific OE to validate the effectiveness of this program at PTN; however, there is OE relevant to components within the scope of the PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. The PTN program is based on the program description in NUREG-2191 (Reference B.3.9), which in turn is based on industry OE. As such, implementation of the PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the CLB through the SPEO.

1. While performing a valve internal inspection (December 2012) on a Unit 4 LP heater bleeder trip valve, minor erosion was found inside the body of the valve. The findings were entered into the CAP. The valve body wall thickness was found to be well above the minimum allowable wall thickness. Based on service conditions an expected wear rate was determined and the number of cycles to reach the minimum wall thickness was determined to be 10 cycles. Based on an inspection frequency of every 5 years no repair of the valve was required. Any new findings in subsequent inspects will be addressed in the CAP.

2. While performing UT scans (September 2004) on two Unit 3 LP heater bleeder trip valves, indication of valve body erosion was noted. The findings were entered into the CAP. A weld buildup was performed in both valve bodies and follow-up inspections were scheduled for subsequent outages.

3. During the fan motor changeout (March 2015) to the Unit 3 motor driven instrument air compressor, an internal inspection revealed housing and internal discharge piping corrosion. The findings were entered into the CAP. Evaluations determined that the corrosion will not impact the components intended function and work has been scheduled to repair the component.

4. In performing maintenance (July 2015) on a plant Air Handler, internal corrosion was noted at the evaporator coil air intake area. The findings were entered into the CAP. This unit has been listed within the PTN air conditioning units replacement project as a long-term action. However, the condition was trended to a work request to remove corrosion and coat the base plate as a short-term action in order to prevent further unit degradation until overhauling is achieved. The corrective action is currently in progress.

<u>Program Health Reports</u>

A review of quarterly program health reports issued since 2012 was conducted to ascertain program performance during the PEO for programs related to the new PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. These program health reports included Heat Exchangers, ISI, Preventive Maintenance, and Structures programs. No relevant information directly associated with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP was identified.

Regulatory Audits and Inspections

The NRC performed Post-Approval Site Inspections for License Renewal for PTN Units 3 and 4 on March 29, 2012 (NRC ADAMS Accession Nos. ML12089A040, Reference B.3.62), July 12, 2012 (NRC ADAMS Accession Nos. ML12195A272, Reference B.3.60) and December 21, 2012 (NRC ADAMS Accession Nos. ML12362A401, Reference B.3.61). The scope of this review included the effectiveness of the Systems and Structures Monitoring Program and the Periodic Surveillance and Preventive Maintenance Program. The inspectors reviewed the licensing basis, implementing procedures, engineering evaluations, personnel qualifications, and non-destructive examination plans which were implemented as stated in the commitment in the LRA. No findings were identified during these inspections. Therefore, the existing programs were found to meet the LRA commitments.

Although the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new program, the OE examples demonstrate that visual inspections are effective for detecting loss of wall thickness and corrosion and surface imperfections for systems not within the scope of other programs. This is further demonstrated by the Program Health Reports for components within the scope of the AMP which did not report any adverse findings and by the program inspections performed by the NRC.

As stated in Section B.1.1, the Containment Spray Piping Inspection Program, credited for the PEO, was found to be effective at managing aging in the December 2017 AMP effectiveness review. However, the program had failed elements. This program is not being continued in the SPEO, but the components will be in the scope of the PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP during the SPEO. Therefore, the failed elements found for the Containment Spray Piping Inspection Program are being included under OE for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.

The Containment Spray Piping Inspection Program failed Element 2, Preventive Actions, and Element 9, Administrative. The failed elements were due to program inspection frequency being revised with the necessary technical justification, but the associated AMP basis document was not updated to the new frequency. The technical justification was verified to be acceptable and the AMP basis document was updated with the new interval in December 2017.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness will be re-assessed for this AMP in 2018 per NEI 14-12.

Conclusion

The PTN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new program that will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.26 Lubricating Oil Analysis

Program Description

The PTN Lubricating Oil Analysis AMP is an existing AMP that will include activities previously performed as part of plant predictive maintenance. The PTN Lubricating Oil Analysis AMP manages loss of material due to corrosion and loss of heat transfer in components exposed to lubricating oil within the scope of SLR by maintaining the required fluid quality to prevent or mitigate age-related degradation. The AMP maintains contaminants in the in-scope lubricating oil systems (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of in leakage and corrosion product buildup. Note that the PTN Lubricating Oil Analysis AMP does not address nonwater-based hydraulic oils, as no screened in components are subjected to a hydraulic oil environment.

Although the PTN Lubricating Oil Analysis AMP is a sampling program, this AMP is to be augmented to manage the effects of aging for SLR. Accordingly, in certain cases identified in NUREG-2191, verification of the effectiveness of the PTN Lubricating Oil Analysis AMP is conducted by the PTN One-Time Inspection AMP (Section B.2.3.20) on selected components at susceptible locations in the lubricating oil system.

The PTN Lubricating Oil Analysis AMP will maintain oil system contaminants (primarily water and particulates) within acceptable limits and check for water and a particle count to detect evidence of contamination by moisture (i.e., cloudy, hazy, or milky in color) or excessive corrosion. If water or particulate contamination is present, a resample is obtained, labeled, and Predictive Maintenance is notified for further evaluation of the samples. The AMP procedures compare oil analysis results against alert levels and limits. If a limit is reached or exceeded, actions to address the condition are taken, which may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the system.

NUREG-2191 Consistency

The PTN Lubricating Oil Analysis AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M39, “Lubricating Oil Analysis.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Lubricating Oil Analysis AMP will be enhanced as follows, for alignment with NUREG-2191. Implementation of this AMP with the following enhancements and changes will be completed no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Monitor for and manage the aging effects associated with in-scope components that are exposed to an environment of lubricating oil. The PTN Lubricating Oil Analysis AMPs in-scope components include piping, piping components, heat exchanger tubes, and reactor coolant pump elements exposed to lubricating oil. The PTN Lubricating Oil Analysis AMP also manages any other plant components subject to lubricating oil environments and listed in applicable AMRs.
2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending	Maintain contaminants in the in-scope lubricating oil systems within acceptable limits through periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with industry standards. All lubricating oil analysis results are to be reviewed and trended to determine if alert levels or limits have been reached or exceeded, as well as, if there are any unusual or adverse trends associated with the oil sampling.
4. Detection of Aging Effects	Sampling and testing of old (used) oil is to be performed following periodic oil changes or on a schedule consistent with equipment manufacturer's recommendations or industry standards (e.g., ASTM D6224-02). Site-specific OE may also be used to adjust the recommended schedule for periodic sampling and testing, when justified by prior sampling results.
6. Acceptance Criteria 7. Corrective Actions	Compare the particulate count of the samples with acceptance criteria for particulates. The acceptance criteria for water and particle concentration within the oil must not exceed limits based on equipment manufacturer's recommendations or industry standards. If an acceptance criteria limit is reached or exceeded, actions to address the condition are to be taken. Corrective actions may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the specified lubricating oil system. Phase-separated water in any amount is not acceptable. If phase-separated water is identified in the sample, then corrective actions are to be initiated to identify the source and correct the issue (e.g., repair/replace component or modify operating conditions).

Operating Experience

Industry Operating Experience

The following examples of OE provide objective evidence that the Lubricating Oil Analysis AMP will be effective in ensuring that intended functions are maintained consistent with the CLB for the SPEO.

Industry operating experience has shown that (a) water in the lubricating oil and (b) particulate contamination may lead to the unplanned unavailability of plant equipment or adversely affect equipment reliability. However, no instances of component failures attributed to lubricating oil contamination have been identified in the industry OE.

Site-Specific Operating Experience

The following review of site-specific operating experience during the first PEO, including past corrective actions, provides objective evidence that the lube oil analysis program is effective at the identification, analysis, and maintaining oil system contaminants (primarily water and particulates) within acceptable limits during the SPEO.

1. In February of 2016, the presence of water in the (common) 2PA AFW lube oil reservoir was found while performing oil sampling. The issue was documented in the CAP for disposition. Water in the AFW oil reservoirs is a condition that has been previously evaluated and determined that such small amounts of water have no effect on the operability of the AFW pumps. The purpose of performing the water removal is to address this condition. The lube oil reservoir capacity is 20 gallons and the location of the foot valve from the bottom of the reservoir is 1 inch. Based on this, one inch of water in the reservoir is equivalent to 1.66 gallons (213.33 oz.) water. It was identified that 36 oz of water retrieved from the AFW pump which are equivalent to 0.16 inches. Since the 36 oz. water is way below the suction of the foot valve, the water will not be drawn out into the oil pump. Shell Turbo T-32 oil is used on the AFW pumps, which is lighter than water. The maximum water allowable with this oil is less or equal to 0.5 percent or 5000 ppm. One of the properties of this oil is its resiliency to mix with water. A visual inspection of the oil sample collected from the oil test port (which draws a sample at approximately the middle of the reservoir) by the Program Engineering Specialist concluded that no apparent mixing of oil and water had occurred. In addition, it was determined under previous experience that this amount of water had no effect on the operability of the AFW pumps. As a result, the CAP item was closed.

2. In March 2015, 3B EDG governor oil sample measured an increase in the concentration of chromium from less than 1 ppm to 33 ppm over a year period, and the particle count increased from 17/12 to 22/14 (guideline is 15/12). The issue was documented in the CAP for disposition. Based on history, the issue is due to introduction of chromate residue from previous coolant system leak above the governor. There were no large wear particles noted or any indication of an aggressive wear mode. The engine has been

performing satisfactorily with no indications of governor degradation (i.e. erratic engine control, frequency and/or load swings, etc.). It was decided that the condition did not negatively impact the operation of the EDG. A follow-up action to resample and flush the oil was created and the CAP item was considered closed.

3. In June 2016, the oil in the (common) A AFW pump reservoir was noted to have a very clear appearance similar to water. The issue was documented in the CAP for disposition. The quality of the oil in the AFW oil reservoir was questioned. Recent maintenance on the Pump was performed followed by an operation run. The oil in the level glass and bull's eyes looked clear, almost water like. Per the Equipment Lubrication Guide, AFW pump is assigned Shell Turbo T 32 oil for use in the reservoir. As part of the dedication testing certification process for new oil, all PC-2 lubricants are tested by an offsite laboratory to ensure critical characteristics of the oil meet stringent Industrial Standards prior to use in the plant. The cleanliness of the oil was then tested on site by Engineering with satisfactory results. Following the maintenance to satisfy the post-maintenance testing (PMT) requirements, AFW was then tested with satisfactory results. There was no indication of a lubrication issues during the run. Following the test run the oil level in the reservoir has been within the normal range per the operator rounds, indicating no gross ingression from an external source (i.e., heat exchanger leak, etc.). The oil was noted to have a very clear appearance similar to water. This is not uncommon for turbine lube oils. It is also not uncommon for oils of the same formulation and viscosity to have differences in tint/color. This questioning attitude is encouraged regarding clarification regarding oil quality.

4. In June 2014 oil analysis test results on the Unit 3 turbine plant cooling water (TPCW) pump B bearing identified abnormal concentration of ferrous wear debris. A ferrographic analysis performed on the sample revealed an aggressive wear mode is present indicative of bearing wear. Based on oil analysis data the 3B TPCW pump bearings were replaced. This example demonstrates that oil monitoring for excessive wear particles is effective at identifying age-related degradation prior to component loss of intended function.

<u>System Health Reports</u>

A review of quarterly system health reports issued from Q1 2012 to Q3 2017 was conducted to ascertain lube oil analysis performance performed under the predictive maintenance (PdM) program during the PEO. The oil analysis database can be accessed online. This allows for data sharing between the PdM nuclear fleet for lessons learned.

The above examples provide objective evidence that the PTN Lubricating Oil Analysis AMP will be capable of maintaining the oil environment in the mechanical systems to the quality required to prevent or mitigate age-related degradation of components within the scope of this AMP. The CAP is constructively used to take effective corrective actions prior to loss of component intended function. The above examples demonstrate that corrective actions include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the system is implemented if lubricating oil sampling and analysis indicates the presence of contaminants. Appropriate guidance for re-evaluation or replacement is provided for samples when degradation is found. Therefore, there is reasonable assurance that continued implementation of the PTN Lubricating Oil Analysis AMP, with the identified enhancements will effectively identify and address age-related degradation prior to component loss of intended function.

Enhancements to the AMP have been identified and implemented as a result of OE. An example of the AMP being enhanced by OE occurred in February 2014, when a self-assessment identified that the PTN procedure for the Oil Analysis Program should be updated to reflect the National Emission Standards for Hazardous Air Pollutants (NESHAP) oil analysis requirements for standby diesel engines per 40 CFR Part 63 subpart ZZZZ. The self-assessment also identified that an oil analysis flow chart should be added to the site procedure for technical clarity and consistency of oil sample processing. Both enhancements were incorporated into the current site procedure. This example demonstrates that this program is continually self-improving and this practice will continue into the SPEO. In addition, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Lubricating Oil Analysis AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.27 Monitoring of Neutron-Absorbing Materials other than Boraflex

Program Description

The PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP, formerly the PTN Metamic® Insert Surveillance Program, is an existing condition monitoring program that is implemented to ensure that degradation of the neutron-absorbing material used in spent fuel pools, that could compromise the criticality analysis, will be detected. This AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to ensure that the required 5 percent subcriticality margin is maintained during the SPEO. This AMP consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or *in situ*. Other testing, monitoring, and analysis activities performed as part of this AMP are described below.

This AMP addresses the aging management of the credited neutron absorbing materials, (i.e., Metamic® inserts and Boral® panels) within the PTN Spent Fuel Pools (SFPs). Rod control cluster assemblies (RCCAs) are credited in the SFP criticality analysis; however, they are not screened into this AMP, since they are regularly replaced. PTN does not credit Boraflex as a neutron-absorber; therefore, there is no need to establish a PTN Boraflex Monitoring AMP, as identified in NUREG-2191, Section XI.M22.

This AMP monitors and manages aging effects associated with neutron-absorbing components/materials that are credited for the SFP criticality analysis. The only such credited neutron-absorbing materials inside the SFP, other than the RCCAs which are not assigned an AMP, are the Metamic® inserts in Regions I and II of the SFP (installed 2012) and the Boral® panels in the cask area rack (installed 2011). Prior to the PEO, the Metamic® insert surveillance portion of this AMP had been implemented by the Metamic® Insert Surveillance Program-which is the existing AMP; however, the existing AMP does not include a surveillance program for the Boral® panels in the SFP cask area. Therefore, the existing AMP will be enhanced for purposes of SLR to manage the Boral® panels.

For these neutron-absorbing materials, gamma irradiation and/or long-term exposure to the wet pool environment may cause loss of material and changes in dimension (such as gap formation, formation of blisters, pits and bulges) that could result in loss of neutron-absorbing capability of the material. The parameters monitored as part of this AMP include the physical condition of the neutron-absorbing materials, such as in-situ gap formation, geometric changes in the material (formation of blisters, pits, and bulges) as observed from coupons or in situ, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the material(s).

The pertinent Metamic® insert surveillance procedure performs visual inspections, weight testing, dimensional measurements, and neutron attenuation testing. Visual inspections on the selected Metamic® inserts monitor for anomalies such as cracking, corrosion, pitting, voids, discoloration, and other surface defects (e.g., bulging) or geometric changes. Weight testing on the selected number of Metamic® inserts determines if the inserts are still within their nominal weight range. The selected Metamic® insert panels also have their length, width, and thickness measured to ensure the dimensions remain within their nominal ranges. Neutron attenuation testing is performed on the selected number of Metamic® coupons, which determines if any significant change in the boron-10 areal density has occurred.

The Boral® panel and Metamic® insert surveillance procedure selects panels and inserts that are to be inspected to ensure they are representative of the neutron absorber materials in the pool. The measurements from periodic inspections and analysis are compared to baseline information or prior measurements and analysis for trend analysis. The approach for relating the measurements to the performance of the SFP neutron absorber materials is specified, considering differences in exposure conditions, vented/nonvented test samples, and spent fuel racks, etc. To ensure the SFP is maintained within the criticality analysis, the Boral® panel and Metamic® insert surveillance procedure will include acceptance criteria that verifies the 5 percent subcriticality margin in maintained.

Corrective actions are to be initiated if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. Corrective actions may consist of providing additional neutron-absorbing capacity with an alternate material, or applying other options, which are available to maintain the subcriticality margin.

NUREG-2191 Consistency

The PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP, with enhancements, will be consistent with the10elements of NUREG-2191, Section XI.M40, “Monitoring of Neutron-Absorbing Materials other than Boraflex.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP will be enhanced as follows, for alignment with NUREG-2191. Implementation of this AMP with the following enhancements and inspections will be completed no later than six months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Update the governing AMP procedure and the Metamic® insert surveillance procedure to state that the frequency of the Metamic® insert inspection and testing depends on the condition of the neutron-absorbing material and is determined and justified with PTN-specific OE, and for each Metamic® insert, the maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE.
5. Monitoring and Trending	Update the Metamic® insert surveillance procedure to state that the observations and measurements from the periodic inspections and coupon testing are compared to baseline information or prior measurements and analyses for trending analysis, projecting future degradation, and projecting the future subcriticality margin of the SFP. This trending of inspection and coupon testing measurements, for the purpose of projecting future Metamic® insert degradation and SFP subcriticality margins, is to also consider differences in Metamic® insert/coupon exposure conditions, whether the test sample is vented or unvented, differences in the spent fuel racks, and other considerations.
7. Corrective Actions	Update the governing AMP procedure to state that corrective actions are initiated if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. Also, update the governing AMP procedure to state that corrective actions may consist of providing additional neutron-absorbing capacity with an alternate material, or applying other options which are available, to maintain the subcriticality margin.

Element Affected	Enhancement
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria 7. Corrective Actions	Create a new surveillance procedure to manage aging effects associated with the Boral® panels in the SFP cask area. This procedure is required to monitor for loss of material and changes in dimension that could result in loss of neutron-absorbing capability of the Boral® panels. The new Boral® panel surveillance procedure monitors parameters associated with the physical condition of the Boral® panels and include in-situ gap formation, geometric changes as observed from coupons or in situ, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the Boral® panels. These parameters are monitored using coupon and/or direct in-situ testing of the Boral® panels to identify their associated loss of material and degradation of neutron absorbing capacity. The frequency of the inspection and testing depends on the condition of the neutron-absorbing material and is determined with site-specific OE; however, the maximum interval between these inspections is not to exceed 10 years, regardless of OE. The new Boral® panel surveillance procedure is required to compare the measurements from periodic inspections and analysis to the baseline information or prior measurements and analysis for trending analysis. In addition to comparing the inspection and testing measurements to the specified acceptance criteria, this procedure trends the measurements to project future Boral ® panel degradation and SFP subcriticality margins. The degradation trending must be based on samples that adequately represent the entire Boral® panel population, and the trending must consider differences in sample exposure conditions, differences in spent fuel cask racks, and possibly other considerations. Additionally, the new Boral® panel surveillance acceptance criteria for the obtained inspection, testing, and analysis measurements must ensure that the 5 percent subcriticality margin within the SFP is maintained. Finally, the new Boral® panel surveillance procedure initiates corrective actions if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. When required, to maintain the subcriticality margin, the possible corrective actions consist of providing additional neutron-absorbing capacity with an alternate material or applying other options which are available.

Operating Experience

Industry Operating Experience

The first U.S. installation of Metamic® occurred in 2007. In the subsequent ten-year period, there has been no significant age-related OE for the Metamic® absorber material in the industry. Even though no significant age-related degradation is anticipated for the material, this aging management program performs regular inspections to be able to identify potential aging effects prior to loss of function of the system.

Site-Specific Operating Experience

The existing Metamic® absorber material AMP at PTN includes a four-year inspection requirement. The initial four-year inspection was performed in 2014, and it included:

- Visual inspection of five inserts.
- Dimensional measurements of two inserts.
- Weight measurements of two inserts.
- Neutron attenuation testing of two coupons.

The results of the visual insert inspections resulted in the identification of no notable degradations other than a few scratches and slight rub wear. These appear to be resultant of moving the insert and were determined to not impact the intended safety functions. All dimensional and weight measurements were within the established acceptance criteria. The two coupons were sent to a contractor for analysis and testing. The test report concluded that the boron-10 areal density exceeds the minimum acceptance criteria and is therefore acceptable. No other significant degradation phenomena were documented. Therefore, the inspections provided indication that the neutron absorbing panels have maintained their safety function.

The above example of OE provides objective evidence that the PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP will be effective in ensuring that intended functions are maintained consistent with the CLB for the SPEO. To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Monitoring of Neutron-Absorbing Materials other than Boraflex AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.28 Buried and Underground Piping and Tanks

The PTN Buried and Underground Piping and Tanks AMP is a new AMP for SLR. This AMP will manage the aging effects (loss of material and cracking) of buried and underground piping constructed of any material including metallic, cementitious, and concrete materials through a combination of preventative, mitigative, and conditioning monitoring/inspection measures. None of the systems within the SLR scope include buried or underground piping constructed of copper, aluminum alloys, or polymers.

PTN is currently managing buried and underground piping via the PTN Asset Management Plan for the Underground Piping and Tank Integrity Program, which is based on NEI 09-14.

There are no buried or underground tanks at PTN.

With respect to this AMP, the following terms are used:

- "Buried" piping and tanks are in direct contact with soil or concrete, and;
- "Underground" piping and tanks are below grade and contained in a tunnel or vault, exposed to air, and located where inspection access is limited

This AMP manages the external surface condition of buried and underground piping for loss of material and cracking for the external surfaces of buried and underground piping fabricated of cast iron, concrete, carbon steel and stainless steel through a combination of the following:

- Preventive measures (i.e., coatings, backfill/compaction and cathodic protection).

  The original PTN coating system consisted of a bituminous resin installed in one coat with a dry film thickness of 10-20 mils. The current plant coating system utilizes Plasite 4550S.

  The original construction specification states that fill shall be limerock quarried from local limestone formations. The pipe bedding section states that underground piping shall be bedded with sand and it shall conform to the requirements of ASTM C-33-86 for fine aggregates. The specification has requirements for both sand and limerock fill. The pipe bedding section states that the sand shall be a minimum of 6 inches thick around the pipe and extend 12 inches above the pipe crown. The same section states that limerock fill shall be used above the sand. There is no noted history of backfill not meeting standards. Recent field inspections of buried pipe at PTN have confirmed that the fill material is in conformance with the original construction specification. The backfill material has been documented as having satisfactory gradation and adequate compaction.

  PTN currently does not have a cathodic protection system for buried and underground piping. The original plant design assumed that based on the use of the limerock fill around the buried piping the groundwater would migrate to the water table and not be retained in the vicinity of the piping. Due to the high permeability of the limerock, corrosion was not expected to be a significant influence. In accordance with the requirements of GALL-SLR Report AMP XI.M41 a cathodic protection system will be installed prior to SPEO.

- Periodic inspection per Table XI.M41-2 and monitoring activities for loss of material or cracking during opportunistic or directed excavations.

  Direct visual inspection are performed on the external surfaces, protective coatings, wrappings, quality of backfill and wall thickness measurements using NDE techniques.

  Additional inspections are performed on steel piping in lieu of fire main testing. The fire water system jockey pump activity (or a similar parameter) will be monitored for unusual trends. The table below provides additional information related to inspections.

  Preventative Action Category F has been selected for monitoring steel piping (which includes cast iron piping) during the initial monitoring period since the cathodic protection system will not be operational during that time period. The number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in Table XI.M41-2, adjusted for a 2-Unit plant site.

Material	**Parameter(s) Monitored**	**No. of Inspections**	**Notes**
Steel (Category F)	Loss of material	11	GALL-SLR Report AMP XI.M41, Table XI.M41-2, quantity increased by 2 in lieu of fire main flow testing
Stainless steel	Loss of material Cracking	2	
Cementitious	Loss of material Cracking	2	

  Loss of material is monitored by visual inspection of the exterior and wall thickness measurements of the piping. Wall thickness is determined by an NDE technique such as UT.

- Mitigative measures

  Electrical isolation (insulating flanges) is provided between piping joints of dissimilar metals.

This AMP does not provide aging management of selective leaching. The PTN Selective Leaching of Materials AMP (Section B.2.3.21) is applied in addition to this program for applicable materials and environments.

The PTN Buried and Underground Piping and Tanks AMP requires the creation of a new governing and inspection procedure created in accordance with NUREG-2191, Section XI.M41, as well as a new sampling plan and WOs to support the new inspections. A new cathodic protection system will also be installed, and an effectiveness review per Table XI.M41-2 of NUREG-2191, Chap. XI.M41 will be performed throughout the 10-year inspection period. This AMP is implemented and inspections begin no earlier than 10 years prior to the SPEO and are completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

NUREG-2191 Consistency

The PTN Buried and Underground Piping and Tanks AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M41, “Buried and Underground Piping and Tanks.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The PTN Buried and Underground Piping and Tanks AMP is a new program to be implemented prior to the SPEO. Therefore, there is no existing program-specific OE to validate the effectiveness of this program at PTN, however there is OE relevant to elements within the scope of the PTN Asset Management Plan for the Underground Piping and Tank Integrity Program (the Asset Management Plan). The AMP is based on the program description in NUREG-2191 (Reference B.3.9), which in turn is based on industry OE. Implementation of the AMP will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the CLB through the SPEO.

A basic element of this new AMP will be the incorporation of the existing Asset Management Plan into this new AMP. The Asset Management Plan is based on industry standard NEI 09-14 Rev 4, "Guidelines for the Management of Underground Piping and Tank Integrity." This NEI document is a nuclear industry initiative to strategically manage the structural and leakage integrity of specific buried piping and below grade piping and tanks. This initiative contains guidelines for risk ranking, inspections, and future maintenance and inspection plans.

<u>Industry Operating Experience</u>

The NEI document is maintained as a living document and is updated based on data from nuclear stations. The Asset Management Plan is updated based on changes in the governing NEI document as well as site specific OE from piping inspections.

The Asset Management Plan identifies relevant nuclear industry OE and identifies the actions taken by PTN in response to this OE. This includes the following:

Date: 1/16/2009

Description: Failed cast iron piping on buried fire protection header at Browns Ferry.

Notes: A large leak was discovered on a 20-foot section of the 14-inch cast iron fire protection header near the west wall of the intake structure. Excavation of the pipe revealed a through wall crack. The apparent cause was an error in the installation as the pipe was not installed per design

PTN Action Taken: PTN has buried cast iron fire protection piping. Several leaks are known to exist and efforts are ongoing to repair them as they are located.

Date: 10/8/2009

Description: Leak in condensate transfer line in condenser bay at Oyster Creek.

Notes: Leakage was found at a turbine building wall penetration. The presence of tritiated water in this piping adds a sense of urgency.

PTN Action Taken: Several inspections at PTN have been at air-to-ground interfaces.

Site-Specific Operating Experience

The Asset Management Plan identifies the inspection history of piping that is within its scope. It documents both internal and external inspections that were performed between 2004 and 2016.

A number of external piping inspections were performed on buried and underground steel and stainless steel piping between 2011 and 2014.

June 2011: Main Feedwater System; 10-foot-long section of 10-inch stainless steel; piping was coated; 3 surface indications most likely caused by the excavation process were identified; minor corrosion cells; piping judged acceptable for continued service; no further action or inspection recommended

March-April 2014: Unit 3 Intake Cooling Water A train header; 12-foot-long section of 30-inch cast iron, cement lined pipe; piping was coated; coating was in fair to good condition with several areas of spot corrosion or rust nodules; coating removed in several areas to investigate the condition of the piping under coating; good coating adhesion; exposed piping appeared to be in good condition; recommended reinspection in 8 years (2022).

March-April 2014: Unit 3 Intake Cooling Water B train header; 12-foot-long section of 30-inch cast iron, cement lined pipe; piping was coated; UT to measure pipe wall thickness; several areas showed pitting graphite corrosion; measured pipe wall thickness greater than the acceptance criteria; recommended reinspection in 8 years (2022).

April 2014: Unit 3 Intake Cooling Water A train header; 12-foot-long section of 30-inch cast iron, cement lined pipe; piping was coated; coating was in good condition with several areas of spot corrosion or rust nodules; UT to measure pipe wall thickness; measured pipe wall thickness greater than the acceptance criteria; recommended reinspection in 8 years (2022).

October 2014: Unit 4 Intake Cooling Water A train header; 10-foot-long section of 30" cast iron, cement lined pipe; piping was coated; coating was in good condition with several areas of corrosion cells; UT to measure pipe wall thickness; measured pipe wall thickness greater than the acceptance criteria; no further action or inspection recommended.

November 2014: Common Waste Disposal pipe - Waste Holdup Tank 1 to Waste Holdup 2 transfer line; 12-foot section of 2" stainless steel located in a pipe tunnel; piping was not coated; no surface corrosion evident; UT to measure pipe wall thickness; measured pipe wall thickness greater than the acceptance criteria; no further direct inspection recommended; future inspections of other piping in this group will be on an opportunistic basis.

November 2014: Common Waste Disposal pipe - Waste Monitor Tank pump discharge to canal; 12-foot section of 2" stainless steel located in a pipe tunnel; piping was not coated; no surface corrosion evident; UT to measure pipe wall thickness; measured pipe wall thickness greater than the acceptance criteria; no further direct inspection recommended; future inspections of other piping in this group will be on an opportunistic basis.

Note that only internal inspections have been performed on the cementitious pipe.

In addition, PTN has experienced a number of pipe leaks and/or breaks in buried piping. Most of these pipe breaks have been in the piping for the fire water and service water systems. These breaks have been documented in the CAP. A review of the documentation in the CAP indicates that typically they have been caused by localized corrosion. These breaks have been repaired and the piping returned to service.

Based on the results of the inspections performed as part of the Asset Management Plan, recommendations were developed for future inspections and/or remediation/repair. The Asset Management Plan identifies future planed inspections. The timing for the reinspection is based on the previous inspection results. This will ensure that any pipe with a remaining life less that the full SPEO is identified for remediation or repair prior to reaching its end of life. For those inspections that are not classified as "opportunistic" it identifies the implementing document that drives the inspection. It also identifies the inspection method -direct visual or UT.

The Asset Management Plan also identifies planned maintenance actions (each involving repair or remediation) over the next 15 years. It also identifies the implementing documents driving this work.

The Asset Management Plan is a self-improving program having been updated several times to reflect changes in the industry standard as well as periodic self-assessments. The CAP is used to track the actions resulting from the self-assessments.

The above examples provide reasonable assurance that the inspection methods that will be implemented by the new Buried and Underground Piping and Tanks Program can detect aging effects including loss of material and cracking for buried and underground piping constructed of metallic, cementitious, and concrete materials. Appropriate guidance for re-evaluation, repair, or replacement will be provided for locations where age-related degradation is found. Periodic self-assessments of the Buried and Underground Piping and Tanks AMP will be performed to identify and correct program elements that need improvement to maintain the quality performance of the program. Therefore, there is confidence that implementation of the new Buried and Underground Piping and Tanks AMP will effectively identify age-related degradation prior to failure or loss of intended function during the SPEO.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Buried and Underground Piping and Tanks AMP is a new program that will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.29 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP, although some of its activities and inspections were formerly a portion of the PTN Periodic Surveillance and Preventive Maintenance Program, the PTN ICW Inspection Program, the PTN Field Erected Tanks Internal Inspection Program, and other site-specific programs. This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.

This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. Visual inspections are scheduled to be conducted on external surfaces when applicable. Where visual inspection of the coated/lined surfaces determines that the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection. This AMP uses the following acceptance criteria:

a. There are no active and/or significant indications of peeling or delamination.

b. Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54 (Reference B.3.20) “Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants.” Blisters should be limited to intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size or frequency should not be increasing between inspections (e.g., ASTM D 714 (Reference B.3.129), “Standard Test Method for Evaluating Degree of Blistering of Paints”).

c. Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54 (Reference B.3.20).

d. Minor cracking and spalling of cementitious coatings/linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material.

e. As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

f. Adhesion testing results will meet or exceed the degree of adhesion recommended by the coating specialist and coating manufacturer when site-specific documents do not have a recommendation embedded.

For tanks and heat exchangers, accessible surfaces are inspected. Piping inspections are sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in NRC RG 1.54. The training and qualification of those individuals also includes guidance from the staff associated with the standards endorsed in RG 1.54. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Active peeling and delamination are not acceptable. Blisters are evaluated by a coatings specialist with the blisters being surrounded by sound material and with the size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed to determine where coating replacement or repair is required. This AMP is supplemented by inspections under the PTN Selective Leaching AMP (Section B.2.3.21), the PTN Open-Cycle Cooling Water System AMP (Section B.2.3.11), and the PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP (Section B.2.3.17).

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP requires the creation of a new governing procedure in accordance with NUREG-2191, Section XI.M42 to monitor for and manage the aging effects associated with the internal surfaces of the in-scope miscellaneous piping, piping components, ducting, heat exchanger components, and other components. Pertinent existing specifications and procedures that supplement the governing procedure are also required to be updated to ensure that the inspection frequency and sampling criteria outlined in NUREG-2191 Element 4 are followed and that all internal coatings are captured.

This AMP is required to be implemented with inspections beginning no earlier than 10 years prior to the SPEO and inspections completed no later than six months prior to the SPEO or the last RFO prior to the SPEO. The inspection interval is either 4 or 6 years as determined by NUREG Section XI.M42, Table XI.M42-1.

NUREG-2191 Consistency

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP for PTN to be implemented prior to the SPEO. Therefore, there is no existing program-specific OE to validate the effectiveness of this program at PTN; however, as explained below, there is OE relevant to components within the scope of the PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP. The PTN program is based on the program description in NUREG-2191 (Reference B.3.9), which in turn is based on industry OE. This program will consider lessons learned from these and other industry OE as it becomes available. As such, implementation of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the CLB through the SPEO.

Industry Operating Experience

In preparing the SLRA, PTN considered the following industry operating experience:

In July 2011, during routine surveillance testing at Seabrook Station (SEA), Service Water flow through the Train 'B' diesel generator heat exchanger (DGHX) was identified as degraded. At that time, the apparent cause of the flow degradation was postulated to be macrofouling of the heat exchanger or flow orifice. At SEA, a corrective action document was initiated to inspect the heat exchanger and flow orifice during the next outage. In October 2011, SEA entered a forced outage for unrelated reasons and the Train 'B' DGHX downstream flow orifice was inspected. Inspection revealed that pieces of Plastisol polyvinyl chloride (PVC) lining of sufficient size so as to partially restrict flow through the orifice had become detached from the pipe. Damaged lining was removed or remediated and the remainder scheduled for replacement with a corrosion resistant, unlined material during the next refueling outage. This piping was installed in 1994 to manage corrosion of a previous piping type discovered in 1992. At the time that the design change was initiated, the liner material was noted to have an anticipated service life of 15–20 years. Inspections at SEA from 1996–2003 found some minor defects and was effective in managing the internal coating until periodic inspection of the Plastisol PVC lined piping was discontinued in favor of a new long-term inspection strategy. At PTN, corrective actions included a requirement to utilize the preventative maintenance process for inspections and replacement activities of "Limited Life" design changes, and the requirement to establish a process that requires monitoring and inspection programs to comply with system Plant Engineering Guidelines.

Site-Specific Operating Experience

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP, although some of its activities and inspections were formerly a portion of the PTN Periodic Surveillance and Preventive Maintenance AMP, the PTN Intake Cooling Water Inspection AMP, the PTN Field Erected Tanks Internal Inspection AMP, and other site-specific AMPs. This OE, which is from other programs, has been evaluated and considered in conjunction with the preparation of this new AMP.

During the spring of 2016 RFO, under the Open-Cycle Cooling Water System Program, the internal surfaces of portions of the Unit 4 ICW system were inspected. The inspected piping included the B ICW header, B ICW pump discharge piping, and C ICW pump discharge piping. The crawl-through inspection concluded the piping inspected was generally in good condition with only 15 locations requiring minor coating repair. Eleven of the 15 coating defects were repaired. Four coating defects, located at the top of the C ICW pump discharge riser, could not be directly inspected or repaired due to the height of the defects and access restrictions. It was determined that based on similar site-specific OE, visible indications during the inspection, and the observed pipe condition, further investigation and repair of these four coating defects is to be performed as soon as practical, but no later than 18 months from the time of the inspection to reduce the likelihood of through-wall defects resulting from coating loss.

In April of 2016, inspections of the intake cooling water discharge piping discovered deficiencies in the coating and a CAP item was created. Of the areas inspected, three were found to have degradation: an elbow, syphon sleeve, and buried pipe portion. The degradation included blistering, peeling, and cracking of the coatings. As a result, the damaged areas were cleaned and repaired and the CAP item was closed.

In 2012, as part of the Outdoor and Large Metallic Atmospheric Tanks program, the following applicable site-specific OE was noted:

- In March 2011, an inspection of the internal surfaces of the Unit 4 CST was performed. The surfaces inspected were found to be free of defects with no blisters, checking, peeling or other lining defects

- In March and April 2011, an inspection of the internal surfaces of the Unit 4 RWST was completed. Small blisters on the coating in isolated areas of the tank wall were noted with diameters of ½ inch or less. When the topcoat of the blistered area was removed, the primer was found to be intact with no sign of corrosion. Several areas of corrosion deposits were observed on the tank floor. Corrective actions were initiated and the deposits were removed and minor corrosion of the substrate was observed. Ultrasonic thickness measurements were taken and the thinnest area observed was 0.295 inches which exceeded the nominal thickness value specified in the tank design. The surface was cleaned and the coating repaired.

- In September 2011, an inspection of the internal surfaces of the DWST was completed. The coatings were found to be in good condition with no significant degradation of surfaces on interior of the tank.

- In March 2012, an inspection of the internal surfaces of the Unit 3 CST was performed. The internal surface condition was acceptable with no blisters, checking, peeling or other lining defects. An area of rust staining was observed in the area of the dome vent. The dome vent was modified and repaired. A similar modification was performed on the Unit 4 CST to improve the tank design.

To date, no enhancements to the AMP have been identified as a result of OE. However, OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new program that will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.30 ASME Section XI, Subsection IWE

Program Description

The PTN ASME Section XI, Subsection IWE AMP is an existing AMP that was formerly the PTN ASME Section XI Subsection IWE ISI Program. This AMP is performed in accordance with ASME Code Section XI, Subsection IWE, and consistent with 10 CFR 50.55a "Codes and Standards," with supplemental recommendations. This AMP includes periodic visual, surface, and volumetric examinations, where applicable, of the metallic liner of class CC pressure-retaining components and their integral attachments.

This AMP provides inspection and examination of containment surfaces, moisture barriers, pressure-retaining bolting, and pressure retaining components for signs of degradation, damage, and other irregularities including discernable liner plate bulges. This AMP also manages loss of material, loss of leak tightness, loss of sealing, and loss of preload, as well as cracking (of dissimilar metal welds associated with penetration sleeves and the fuel transfer tube). Coated areas are examined for distress of the underlying metal shell or liner. Acceptability of inaccessible areas of the concrete containment steel liner is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas. Inspection results are compared with prior recorded results in acceptance of components for continued service. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the condition is determined and that corrective action is taken to preclude recurrence.

If site-specific OE identified after the approval of the SLRA triggers the requirement to implement a one-time supplemental volumetric examination, then this inspection is performed by sampling randomly-selected, as well as focused, liner locations susceptible to corrosion that are inaccessible from one side. The trigger for this one-time examination is site-specific occurrence or recurrence of liner corrosion that is determined to originate from the inaccessible (concrete) side. Any such instance would be identified through code inspections performed since June 6, 2002.

Coated surfaces are visually inspected for evidence of conditions that indicate degradation of the underlying base metal. Coatings are a design feature of the base material and are not credited with managing loss of material. The PTN Protective Coating Monitoring and Maintenance AMP (Section B.2.3.37) is used for the monitoring and maintenance of protective containment coatings in relation to reasonable assurance of emergency core cooling system operability. Concrete portions of containments are inspected by the separate PTN ASME Section XI, Subsection IWL AMP (Section B.2.3.31).

Surface conditions are monitored through visual examinations to determine the existence of corrosion. Surfaces are examined for evidence of flaking, blistering, peeling, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, or other signs of surface irregularities. Pressure-retaining bolting is examined for loosening and material conditions that cause the bolted connection to affect either containment leak-tightness or structural integrity. Moisture barriers are visually inspected for degradation per Category E-A.

PTN has no pressure-retaining components subject to cyclic loading without CLB fatigue analysis. Pressure retaining components associated with the containment liner, including attachments and penetrations, are addressed by a fatigue evaluation.

This AMP meets the requirements of IWE-3000 and IWE-3410. Most of the acceptance standards rely on visual examinations. Inspection results are evaluated against the acceptance standards provided in the PTN IWE Program. Areas identified with damage or degradation that exceed acceptance standards require an engineering evaluation or require correction by repair or replacement. Such areas are corrected by repair or replacement in accordance with IWE-3122 or accepted by engineering evaluation.

NUREG-2191 Consistency

The PTN ASME Section XI, Subsection IWE AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S1, “ASME Section XI, Subsection IWE.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN ASME Section XI, Subsection IWE AMP will be enhanced as follows for alignment with NUREG-2191. The changes and enhancements will be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Include preventive actions, consistent with industry guidance, to provide reasonable assurance that bolting integrity is maintained for structural bolting. That is, proper bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload. Include indication that if high strength bolting is used, the appropriate guidance is to be considered.

Element Affected	Enhancement
4. Detection of Aging Effects	If site-specific OE identified after the approval of the SLRA triggers the requirement to implement a one-time supplemental volumetric examination, then perform this inspection by sampling randomly-selected, as well as focused, liner locations susceptible to corrosion that are inaccessible from one side. The trigger for this one-time examination is site-specific occurrence or recurrence of liner corrosion that is determined to originate from the inaccessible (concrete) side. Any such instance would be identified through code inspections performed since June 6, 2002.

Operating Experience

Industry Operating Experience

NRC IN 2010-12 was issued to inform addressees of the then-recent issues involving the corrosion of the steel reactor containing building liner. The NRC expected recipients to review the information for applicability of their facilities and to consider actions, as appropriate, to avoid similar problems. In response, PTN issued an AR which evaluated that the containment liner inspection programs in effect at PTN are effective in detecting and addressing any found degradation of the containment liner due to corrosion, and ensure that the structural integrity and design function of the component are maintained. Additionally, the planned ASME Section XI Subsection IWE inspection in 2010 effectively located and corrected liner plate corrosion. Further discussion is located in Section iii below.

The examples above demonstrate that the PTN ASME Section XI, Subsection IWE AMP reviews OE and incorporates applicable industry OE into the program. This ensures that the AMP will continue to be effective during the SPEO as it is informed and enhanced by industry OE.

Site-Specific Operating Experience

The PTN ASME Section XI, Subsection IWE AMP is a mature, established program that remains effective.

The PTN IWE AMP was assessed as part of the July 2012 NRC post-approval site inspection (ML12089A040, Reference B.3.62) prior to entering the original PEO. This site inspection identified no findings related to the PTN ASME Section XI, Subsection IWE AMP.

The quarterly PTN ASME Section XI, Subsection IWE AMP health reports are also developed and trended. Quarterly health reports for years 2012 (post NRC post-approval site inspection) through 2017 were reviewed as part of this OE analysis and show that the existing Inservice Inspection (ISI) Programs and Plans were developed and prepared to meet the requirements of the ASME Section XI, Subsection IWE AMP. There have been no implementation issues related to inspections, surveillances or work order productivity that affect backlogs or equipment or ISI Program Health.

FPL Quality Assurance surveillances and reviews have been performed with no deficiencies identified. 2010 ISI/Engineering Functional Area Audit: This audit reviewed the corrective actions from the 2008 CSI Audit and a 2009 CSI QHSA. The audit concluded that repair/replacement activities were performed and documented in accordance with program requirements. 2011 Engineering Programs/Engineering Functional Area Audit: This audit included an assessment of elements of the inservice testing and non-destructive examination (NDE) programs. All elements assessed were determined to be satisfactory and no issues were identified.

The AMP effectiveness was again confirmed in the recent effectiveness review against the criteria provided in NEI 14-12. An administrative deficiency was identified because IWE outage scopes are not identified as License Renewal commitment examinations. This administrative deficiency has been entered in the CAP for resolution.

The following review of site-specific OE provides examples of how PTN is managing aging effects associated with the PTN ASME Section XI, Subsection IWE:

1. IWE examinations were performed by the Nuclear Engineering Component, Support and Inspections Group on the containment liner during the Unit 4 2011, 2012 and 2014 refueling outages and the Unit 3 2012, 2013 and 2015 refueling outages. Preservice examinations were performed in areas of coating repairs to the containment metallic liner and moisture barrier seal. ARs were written to document indications identified during the examinations:

    - While performing a scheduled ASME Code Section XI Subsection IWE Visual Inspection of the U3 Containment Moisture Barrier in October 2015, fifteen areas of degraded or damaged sealant were noted. The moisture barrier is a water tight seal installed between the 14-ft elevation concrete floor and a leak chase angle (toe plate) attached to the containment liner. The sealant was found to have physical damage, loss of adhesion, and tearing. The damage was located throughout the circumference of the containment. No degradation of the liner itself was identified. The damage was likely caused by ordinary outage activities due to the moisture barrier being an elastomeric material located in a congested area. The damage was not considered excessive to the extent that actions would be required to prevent it from recurring. The moisture barrier was repaired and satisfactorily re-inspected in accordance with ASME Section XI Subsection IWE.

    - While performing a scheduled ASME Code Section XI Subsection IWE detailed visual inspection of the Unit 3 liner plate/toe plate in October 2015, a through-wall hole was identified in the toe plate between the moisture barrier and liner wall. Degraded coatings, chipped paint, missing primer (bare metal), and rust were also noted throughout all zones of containment at the 14 ft elevation. No degradation of the liner itself was identified. The condition evaluation determined that the existing hole should be enlarged to provide an opportunistic inspection of the liner plate. The resulting inspection of the liner plate by ISI documented satisfactory conditions and repair of the hole was completed in accordance with approved generic repair details.

- While performing a scheduled ASME Code Section XI Subsection IWE visual inspection of the U4 Containment Moisture Barrier in April 2016, six (6) areas of degraded or damaged sealant were noted. Engineering determined the moisture barrier would perform its function once the damaged areas were repaired. The damage was likely caused by ordinary outage activities since the moisture barrier is an elastomeric material located in a congested area. The damage was not considered severe enough that actions would be required to prevent it from recurring. The moisture barrier was repaired satisfactorily.

- While performing a scheduled ASME Code Section XI Subsection IWE detailed visual inspection of the U4 liner plate/toe plate interface in April 2016, degraded coatings, chipped and flaking paint, missing primer (bare metal), and rust were observed throughout all zones in containment at the 14 ft elevation. Engineering evaluated the damaged areas of the toe plate/ liner. The resulting exposed metal liner portions had incurred only surface corrosion/discoloration, which did not affect the component intended function. Surface corrosion was removed and the exposed areas were resealed with their respective coating materials. The coating deficiencies were incurred from outage-related activities.

2. The PTN ASME Section XI Subsection IWE AMP has been effective in responding to industry OE. As noted above, when NRC issued IN 2010-12 to inform addressees of recent issues involving the corrosion of the steel reactor containment building liner, PTN addressed the information notice. Additionally, the planned ASME Section XI Subsection IWE inspection in 2010 effectively located and corrected liner plate corrosion.

   In October 2010, while performing an inspection in accordance with the planned ASME Section XI, Subsection IWE, a hole was discovered in the liner in the Unit 3 reactor sump. Augmented visual and ultrasonic examinations revealed a surrounding area with wall thickness measurements less than minimum and additional through-wall holes. The root cause of degradation was determined to be long-term corrosion of the carbon steel liner from the containment side due to boric acid. It was also documented that the coating system used was not designed for periodic immersion in borated water allowing exposure of the containment liner. There was no evidence of corrosion degradation on the concrete side of the liner plate. Additionally, results of then-recent containment integrated leak rate testing (in 2005) indicated that the required leak tight integrity was maintained. Integrated leak rate testing was also performed in 2012 with satisfactory results. These performance tests are an indication that even though degradation was discovered in 2010, the component continued to perform its intended function.

   In order to restore full qualification of the liner plate, the degraded section was replaced and inspected in accordance with the rules of the ASME Code. A new coating system suitable for immersion service was applied on the liner plate in the lower region of the entire reactor pit area.

Additional causes for the liner plate degradation were also evaluated and corrected. This included that Boric Acid Corrosion Program inspectors were focused primarily on the pressurized borated systems, and engineering evaluators did not recognize the potential for coating system failure and boric acid corrosion of the containment liner plate in the reactor pit area. The Boric Acid Corrosion Program was revised to identify the upper reactor cavity as a potential source of borated water leakage and the expectations associated with addressing the source. Also, a training needs analysis was performed and appropriate training implanted for Boric Acid Corrosion Program inspectors. Another contributing cause was that the IWE inspector failed to detect degradation in 2006. This was addressed by developing minimum training requirements above the requirements of the ASME Code for IWE inspectors and by enhancing the visual inspection data sheet to provide more direction/guidance on potential defects in specific regions. Additionally, the Appendix J Program Visual Inspection Procedure did not include the liner plate in the reactor pit area. This was addressed by adding the reactor pit area to the visual inspection procedure.

Due to the discovery items associated with the Unit 3 containment liner degradation, the potential existed for the same issues to occur in the Unit 4 containment liner. The potential for degradation of the Unit 4 containment liner was evaluated in 2010 and confirmed to have acceptable wall thickness. The new coating system suitable for immersion service was also applied on the Unit 4 liner plate in the lower region of the entire reactor pit area.

Enhancements to the AMP have been identified and implemented as a result of OE. Examples of such enhancements are listed in liner plate corrosion OE discussion above. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12. The site-specific examples of OE demonstrate that scheduled inspections executed through the ASME Section XI Subsection IWE AMP and follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

Conclusion

The PTN ASME Section XI, Subsection IWE AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.31 ASME Section XI, Subsection IWL

Program Description

The PTN ASME Section XI, Subsection IWL AMP is an existing condition monitoring AMP, formerly the PTN ASME Section XI, Subsection IWL ISI Program, which implements the examination requirements of the ASME Code Section XI, Subsection IWL, as mandated by 10 CFR 50.55a “Codes and Standards.” The scope of the program includes reinforced concrete and unbonded post-tensioning system.

The current program complies with ASME Code Section XI, Subsection IWL, 2001 Edition through 2003 Addenda (Reference B.3.122), supplemented with the applicable requirements of 10 CFR 50.55a(b)(2). This program is consistent with provisions in 10 CFR 50.55a that specify the use of the ASME Code edition in effect 12 months prior to the start of the start of the inspection interval. PTN will use the ASME Code edition consistent with the provisions of 10 CFR 50.55a during the SPEO. In accordance with 10 CFR 50.55a(g)(4)(ii), 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 twelve months before the start of the inspection interval.

The primary inspection method is a visual examination, supplemented by testing. The inspections associated with this AMP assess the quality and structural performance of the containment structures and associated post-tensioning systems. Accessible concrete surfaces are subject to periodic visual inspections to detect deterioration and distress, including loss of material (spalling, scaling), cracking, increase in porosity and permeability, and loss of bond in the air-outdoor (uncontrolled) environments.

Tendon wires and tendon anchorage hardware surfaces are inspected for loss of material, cracking, and mechanical damage. The tendon corrosion protection medium is tested for the pH, presence of free water, and soluble ion concentration.

The PTN ASME Section XI, Subsection IWL AMP tests selected sample tendons for yield strength, ultimate tensile strength, and elongation. The sample includes hoop tendons, vertical tendons and dome tendons. The frequency of tendon inspections is consistent with IWL-2421 for sites with two units. The assessment and trending of measured tendon prestressing forces is managed by the PTN Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3).

The Subsection IWL requirements are supplemented to include quantitative acceptance criteria for the evaluation of concrete surfaces based on the "Evaluation Criteria" provided in Chapter 5 of American Concrete Institute (ACI) 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." Inspection results are compared with prior recorded results in acceptance of components for continued service through the IWL AMP.

Additionally, inaccessible areas of the reinforced containment concrete structure, such as the dome, wall, basemat, ring girders and buttresses, are managed by the PTN ASME Section XI, Subsection IWL AMP, supplemented by the Structures Monitoring AMP (Section B.2.3.35). Steel liners for the concrete containments, and their integral attachments, are included within the scope of the PTN ASME Section XI, Subsection IWE AMP(Section B.2.3.30).

Quantitative acceptance criteria for document and trending inspection results through photography is provided in Chapter 5 of ACI 349.3R.

This AMP includes enhancements, as listed in the table below, to ensure that calculation of predicted tendon forces are in accordance with RG 1.35.1, which provides an acceptable methodology for use during the SPEO.

NUREG-2191 Consistency

The PTN ASME Section XI, Subsection IWL AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S2, “ASME Section XI, Subsection IWL.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN ASME Section XI, Subsection IWL AMP will be enhanced as follows, for alignment with NUREG-2191. There are no new inspections required for SLR; however, existing inspection frequencies may change. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
6. Acceptance Criteria	Update the pertinent AMP procedure to calculate the predicted tendon forces in accordance with NRC RG 1.35.1 (Reference B.3.19), “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments,” which provides an acceptable methodology for use through the SPEO.

Operating Experience

<u>Industry Operating Experience</u>

As described, industry operating experience indicates degraded conditions of post tensioning systems can be of concern due to potential loss of material and loss of prestress during extended periods of operation. As a result, the IWL program will be enhanced to incorporate the methodology of RG 1.35.1 for determining prestressing forces.

By way of background, ASME Code Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, the prestressing tendon inspections were performed in accordance with the guidance provided in RG 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments." Industry OE pertaining to degradation of reinforced concrete in concrete containments was gained through the inspections required by 10 CFR 50.55a(g)(4) (i.e., Subsection IWL), 10 CFR Part 50, Appendix J, and ad hoc inspections conducted by licensees and the NRC. NUREG-1522, "Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures," described instances of cracked, spalled, and degraded concrete for reinforced and prestressed concrete containments.

The NUREG also described cracked anchor heads for the prestressing tendons at three prestressed concrete containments. NRC Information Notice (IN) 99-10, Revision 1, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment," described occurrences of degradation in prestressing systems. IN 2010-14, "Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria," describes issues concerning the containment concrete surface condition examination frequency and acceptance criteria. The IWL program considers the degradation concerns described in these generic communications.

Site-Specific Operating Experience

The containment tendon examination program has been conducted since initial startup of both Units 3 and 4 on 5-year intervals. The initial containment tendon surveillance examination requirements incorporated the general criteria and requirements of NRC RG 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments." The program transitioned to the requirements of ASME Code Section XI, Subsection IWL due to the incorporation of the code into 10 CFR 50.55a. The effectiveness of the PTN ASME Section XI, Subsection IWL AMP was reviewed in inspection notebooks compiled in support of the July 2012 NRC post-approval site inspection (ML12089A040, Reference B.3.62) prior to entering the original period of extended operation (PEO). The containment structure post-tensioning system surveillances performed as part of this program were more recently performed on the PTN Units 3 and 4 containment buildings in 2012 (40 year inspection) and 2017 (45-year inspection). These surveillances demonstrated that the actual measured pre-stressing forces were well above the predicted effective preload.

Examinations for the 40-year inspection for subsection IWL began in February 2011 and continued until February 2013 for the second 10-year interval work. The 40th year inspection report concluded that the containment structure had experienced no abnormal degradation of the post-tensioning system.

In 2012, the NRC Senior Resident Inspector visually identified a number of indications in the Unit 4 dome concrete. An IWL qualified concrete inspector examined the indications in the identified and surrounding area. CE 1737608-02 concluded that the cracks were measured to be less than 0.015 in (width) and did not exhibit any indication of being active. Therefore, the condition was classified as acceptable. An issue/event entry was added to the program health report for future reference.

During the 2017 Unit 3 and Unit 4 RFOs, examinations were performed by the Nuclear Engineering Component, Support, and Inspections Group for the 45-year inspection for Subsection IWL for the second 10-year interval work. The final inspection reports concluded that the containment structure had experienced no abnormal degradation of the post-tensioning system.

An example of the overall effectiveness of the tendon inspection program is supported by the results of the 20th year tendon surveillance. The measured lift-off forces for a number of randomly selected surveillance tendons were below the predicted lower limit. CAP items and a License Event Report were issued. In accordance with the Technical Specifications, engineering evaluations were prepared and concluded that the lower than expected tendon lift-off forces were caused by greater than expected tendon wire relaxation losses due to average tendon temperatures higher than originally considered. To accommodate the increased prestress losses, a license amendment was submitted and approved to reduce the containment design pressure from 59 psig to 55 psig, and a containment re-analysis was performed to determine the new minimum required prestress forces to maintain licensing basis requirements. The results of the reanalysis are provided in UFSAR, Section 5.1.3. The predicted lower limit values were also recalculated and lowered to accommodate the lower tendon lift off forces observed. Based on the results of the re-analysis the lower tendon lift off forces were determined to be acceptable.

The ASME Section XI, Subsection IWL AMP incorporates all of the inspection criteria and guidelines of the previous tendon inspection program attributes and is implemented using existing plant procedures.

The above examples of site-specific operating experience during the first PEO, including past corrective actions, provides objective evidence that the IWL aging management program effectively manages aging effects so that the intended functions of SCs within the scope of the program will be maintained during the SPEO.

To date, no enhancements to the ASME Section XI, Subsection IWL AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Although the containment cathodic protection system is not credited for aging management, the NRC identified a green non-cited violation for failure to take timely corrective action to maintain the Unit 3 and 4 containment cathodic protection system (Reference B.3.150). FPL concluded that the containment structure was operable but non-conforming and established plans to monitor the potentially impacted inaccessible areas through continued performance of the PTN

ASME Section XI, Subsection IWE and IWL AMPs until actions are taken to restore the cathodic protection system.

Conclusion

The PTN ASME Section XI, Subsection IWL AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.32 ASME Section XI, Subsection IWF

Program Description

The ASME Section XI, Subsection IWF AMP is an existing condition monitoring program that consists of periodic visual examination of ASME Code Section XI Class 1, 2, and 3 supports for ASME piping and components for signs of degradation such as corrosion; cracking, deformation; misalignment of supports; missing, detached, or loosened support items; loss of integrity of welds; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Bolting for Class 1, 2, and 3, piping and component supports is also included and inspected for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity. Associated sliding surfaces, and vibration isolation elements are also inspected for loss of material or mechanical or isolation function.

The ASME Section XI, Subsection IWF AMP provides inspection and acceptance criteria and meets the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, 2007 edition with addenda through 2008, and 10 CFR 50.55a(b)(2) for Class 1, 2, 3 piping and components and their associated supports. The primary inspection method employed is visual examination. NDE indications are evaluated against the acceptance standards of ASME Code Section XI. Examinations that reveal indications are evaluated. Examinations that reveal flaws or relevant conditions that exceed the referenced acceptance standard, are expanded to include additional examinations during the current outage. The scope of inspection for supports is based on sampling of the total support population. The sample size varies depending on the ASME Code Class. The largest sample size is specified for the most critical supports (ASME Code Class 1). The sample size decreases for the less critical supports (ASME Code Class 2 and 3). Tactile inspections of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect is also included.

This AMP emphasizes proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload of structural bolting and cracking of high-strength bolting. As noted below in the enhancement discussion, the AMP also includes the preventive actions for storage requirements of high-strength bolts. The requirements of ASME Code Section XI, Subsection IWF are supplemented to include volumetric examination of high-strength bolting for cracking. This AMP will also include a one-time inspection within 5 years prior to the SPEO of an additional 5 percent of piping supports from the remaining IWF population that are considered most susceptible to age-related degradation.

NUREG-2191 Consistency

The PTN ASME Section XI, Subsection IWF AMP, with exception and enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S3, “ASME Section XI, Subsection IWF.”

Exceptions to NUREG-2191

NUREG-2191 recommends using bolting material for structural applications that have an actual measured yield strength limited to less than 1,034 megapascals (MPa) (150 kilo-pounds per square inch) (NUREG-1339), as a preventive measure that can reduce the potential for SSC. High strength bolts, including ASTM A-325 and ASTM A-490 are used in structural applications at PTN and bolting replacement and maintenance activities. Site documentation indicates bolts conforming to ASTM A-490, "Heat Treated Structural Bolts, 150 ksi Minimum Tensile Strength" are installed on structural steel components. PTN performs visual inspection of high-strength bolting in accordance with ASTM A-325 and A-490. PTN also limits the use of sulfur containing lubricants as a preventive measure to reduce SCC of high-yield bolting. Additionally, ASME Section XI, Subsection IWF AMP will be enhanced to explicitly state that lubricants cannot contain Molybdenum Disulfide. The other preventive actions (use of appropriate lubricants, appropriate installation torque, and appropriate storage) in NUREG-2191 XI.S3 AMP that can reduce the potential for cracking are met by the PTN ASME Section XI, Subsection IWF AMP. The exception is acceptable because PTN meets all other program element requirements for structural bolting. Furthermore, the PTN AMP includes an enhancement for volumetric examination of high-strength bolts in order to provide reasonable assurance that SCC is not occurring.

Enhancements

The PTN ASME Section XI, Subsection IWF AMP will be enhanced for alignment with NUREG-2191 as discussed below. This AMP with the following enhancements is to be implemented and a one-time inspection of an additional 5 percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports is to be conducted within 5 years prior to the SPEO. Inspections that are to be completed prior to the SPEO are completed 6 months prior to the SPEO or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Store high strength bolts in accordance with Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using High-Strength Bolts”.
3. Parameters Monitored or Inspected	Include volumetric examination of high-strength bolting in sizes greater than 1 inch nominal diameter (including ASTM A490 bolts and equivalent bolts) for evidence of SCC.

Element Affected	Enhancement
4. Detection of Aging Effects	Include a one-time inspection, within 5 years of entering the SPEO, of an additional 5 percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports, which are not exempt from examination, that is focused on supports selected from the remaining IWF population that are considered most susceptible to age-related degradation. Include tactile inspection (feeling, prodding) of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect. Include volumetric examination, comparable to Table IWB-2500-1, Examination Category B-G-1, at least once per interval for a sample of high-strength bolting selected to provide reasonable assurance that SCC is not occurring for the entire population of high-strength bolts.

Operating Experience

Industry Operating Experience

NRC IN 2009-04 was issued to alert addressees to a possible age-related degradation of mechanical constant supports that may adversely impact design stresses on piping systems. The information notice was issued in response to an event at the Palo Verde Nuclear Generating Station, Unit 2. During a refueling outage the licensee tested four safety-related constant supports as part of an investigation for failures on these components and associated beam attachments for these supports. The measured vibrations on the main steam lines were below the analyzed values of displacement and velocity but were above the ASME requirement.

In response to IN 2009-04, PTN conducted an investigation in April 2009 to determine the presence of constant support hangers at PTN Units 3 and 4 and to perform an inspection to determine the present condition of those hangers. As a result of the review, it was determined that there are five constant support hangers in each unit and 16 constant spring cans to which this information notice was applicable. All of the identified constant support hangers are associated with the main steam system, downstream of the main steam isolation valves, in the turbine building. Since all piping supports located outside of the PTN containment buildings are managed by the Structures Monitoring AMP, IN 2009-04 is not applicable to the PTN ASME Section XI, Subsection IWF AMP.

Site-Specific Operating Experience

The PTN ASME Section XI, Subsection IWF AMP is a mature, established program that remains effective. PTN reviewed site-specific OE in preparing the SLRA. Based on a review of site-specific OE, the PTN ASME Section XI, Subsection IWF AMP has been demonstrated to be adequate to manage aging. Specific OE that provides objective evidence supporting this conclusion includes the following:

The July 2012 NRC post-approval site inspection for original license renewal (ML12089A040, Reference B.3.62), conducted prior to entering the original PEO, identified no findings related to the PTN ASME Section XI, Subsection IWF AMP.

FPL Quality Assurance surveillances and reviews have been performed with no deficiencies identified. The 2010 ISI/Engineering Functional Area Audit reviewed the corrective actions from the 2008 CSI Audit and a 2009 QHSA. The audit concluded that repair/replacement activities were performed and documented in accordance with program requirements. The 2011 Engineering Programs/Engineering Functional Area Audit included an assessment of elements of the inservice testing and NDE programs. All elements assessed were determined to be satisfactory and no issues were identified.

The quarterly PTN ASME Section XI, Subsection IWF AMP health reports are also developed and trended. All quarterly health reports for years 2012 (post NRC post-approval site inspection for original license renewal) through 2017 indicate that the existing ISI Programs and Plans are developed and prepared to meet the requirements of the ASME Section XI, Subsection IWF. There have been no implementation issues related to inspections, surveillances or work order productivity that affect backlogs, equipment or ISI Program Health.

The AMP effectiveness was again confirmed in the 2017 FPL effectiveness review against the criteria provided in NEI 14-12. An administrative deficiency was identified that IWF outage scopes are not identified as License Renewal commitment examinations. This administrative deficiency has been entered in the CAP for resolution.

ISIs are performed during the Unit 3 RFOs and Unit 4 RFOs. The following review of site-specific OE provides examples of how PTN is managing aging effects associated with the ASME Section XI, Subsection IWF AMP.

1. In November 2015, while performing a scheduled ASME Section XI Subsection IWF examination, the nuts on the east side of the baseplate of a pipe support were identified as loose. The deficiency was entered into the CAP, and the baseplate was analyzed for the as-found condition. After analysis, the support was determined to be structurally qualified and will continue to perform its intended function. No further action was required.

2. During system engineering Unit 3 walkdowns in March of 2015, deformation (minor bend) and minor surface corrosion were noted on a spring can hanger for the A S/G flow element. The condition was entered into the CAP and the resulting evaluation determined that the condition did not impact the ability of the spring can to perform its design function, and there was no threat to equipment reliability. The bent section of hanger was replaced.

3. In October of 2015, while performing a scheduled Unit 3 Section XI examination, debris was observed inside the north spring can of a spring hanger on the surge line. The debris

was determined to not impact the operability of the spring can, as the debris was not wedged between the spring coils. The debris was removed from the spring can as part of the CAP action.

The examples above provide objective evidence that the ASME Section XI, Subsection IWF program inspection activities are effective in identification of susceptible locations and that the CAP is effectively used to take corrective actions prior to loss of component intended function. NRC and FPL reviews of the AMP, initiation of corrective actions, and subsequent corrective actions prior to loss of intended function, demonstrates that the PTN ASME Section XI, Subsection IWF AMP, remains effective. Additionally, the OE relative to the PTN ASME Section XI, Subsection IWF AMP provides objective evidence that the existing program will effectively monitor and detect the aging effects of loss of material and loss of mechanical function for supports for Class 1, 2, and 3 piping and components through the SPEO. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where age-related degradation is found. Periodic self-assessments of the PTN ASME Section XI, Subsection IWF AMP are performed to identify and correct program elements that need improvement to maintain the quality performance of the program. Additionally, the quarterly health reports from 2012 to present demonstrate that the AMP is currently meeting the requirements of the ASME Section XI, Subsection IWF.

To date, no enhancements to the AMP have been identified as a result of OE during the initial PEO. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12. Therefore, there is confidence that continued implementation of the PTN ASME Section XI, Subsection IWF AMP will effectively identify age-related degradation prior to failure or loss of intended function during the SPEO.

Conclusion

The PTN ASME Section XI, Subsection IWF AMP, with the enhancements, will provide reasonable assurance that aging effects will be managed so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.33 10 CFR Part 50, Appendix J

Program Description

The PTN 10 CFR Part 50, Appendix J AMP is an existing AMP that was formerly the PTN Containment Leak Rate Testing Program, although, it was not previously credited for license renewal. The PTN 10 CFR Part 50, Appendix J AMP is a performance monitoring program that monitors the leakage rates through the containment system, its shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria.

This AMP is implemented in accordance with the 10 CFR Part 50, Appendix J, NRC RG 1.163 (Reference B.3.28), “Performance Based Containment Leak-Test Program,” NEI 94-01 (Reference B.3.86), “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” and ANSI/ANS 56.8-1994 (Reference B.3.119), “Containment System Leakage Testing Requirements.” Additionally, this AMP is subject to the requirements of 10 CFR Part 54. This AMP credits the existing program required by 10 CFR Part 50, Appendix J, and augments it to ensure that all containment pressure-retaining components are managed for age-related degradation.

The PTN containment system consists of a containment structure (containment), and a number of electrical, mechanical, equipment hatch, and personnel air lock penetrations. As described in 10 CFR Part 50, Appendix J, periodic containment leak rate tests are required to ensure that (a) leakage through these containments or systems and components penetrating these containments does not exceed allowable leakage rates specified in the PTN TS (Reference B.3.147) and (b) integrity of the containment structure is maintained during its service life. Appendix J of 10 CFR Part 50 provides two options, Option A and Option B, to meet the requirements of a containment leak rate test (LRT) program. PTN uses the performance-based approach, Option B. The NRC RG 1.163 (Reference B.3.28), NEI 94-01 (Reference B.3.86), and ANSI/ANS 56.8-1994 (Reference B.3.119) provide additional information regarding Option B.

The monitored parameters are leakage rates through the containment shell, containment liner, penetrations, associated welds, access openings, and associated pressure boundary components. Three types of tests (Type A, Type B, and Type C) are performed at PTN as specified by 10 CFR Part 50, Appendix J, Option B. Type A integrated leak rate tests (ILRT) determine the overall containment integrated leakage rate, at the calculated peak containment internal pressure related to the design basis loss of coolant accident. Type B (containment penetration leak rate) tests detect local leaks and measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Type C (containment isolation valve leak rate) tests detect local leaks and measure leakage across containment isolation valves installed in containment penetrations or lines penetrating the containment.

Additionally, 10 CFR Part 50, Appendix J, requires a general visual inspection of the accessible interior and exterior surfaces of the containment structures and components to be performed prior to any Type A test and at periodic intervals between tests based on the performance of the containment system. The PTN 10 CFR Part 50, Appendix J AMP meets this requirement with its visual inspection procedures. Additionally, the PTN 10 CFR Part 50, Appendix J AMP inspections may be performed in conjunction with the PTN AMP associated with ASME Code Section XI, Subsections IWE and IWL, to ensure that all evidence of structural deterioration that may affect the containment structure leakage, integrity, or the performance of the Type A test is identified.

Corrective actions are taken in accordance with Appendix J and NEI 94-01. When leakage rates do not meet the acceptance criteria, an evaluation is performed to identify the cause of the unacceptable performance and appropriate corrective actions are taken.

NUREG-2191 Consistency

The PTN 10 CFR Part 50, Appendix J AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S4, "10 CFR Part 50, Appendix J."

Exceptions to NUREG-2191

None.

Enhancements

The PTN 10 CFR Part 50, Appendix J AMP will be enhanced as follows, for alignment with NUREG-2191 Section XI.S4 and 10 CFR Part 50, Appendix J. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Augment the existing program required by 10 CFR Part 50 Appendix J, by ensuring that all containment pressure-retaining components are managed for age-related degradation. Update the definitions for Type A, Type B, and Type C tests in the fleet and governing procedures to align with their respective definitions in 10 CFR Part 50, Appendix J, Section II.

Operating Experience

Industry Operating Experience

To date, the Appendix J containment LRT program, in conjunction with the containment ISI program, has been effective in preventing unacceptable leakage through the containment pressure boundary. Review for recent industry operating experience did not identify any major issues regarding the 10 CFR Part 50, Appendix J AMP.

Site-Specific Operating Experience

The PTN 10 CFR Part 50, Appendix J AMP (formerly the PTN Containment Leak Rate Testing Program, which was not previously credited for license renewal) is a mature, established program that remains effective. The PTN 10 CFR Part 50, Appendix J AMP is a performance monitoring program.

The quarterly PTN 10 CFR Part 50, Appendix J AMP health reports are also developed and trended. All quarterly health reports for years 2012 (post NRC post-approval site inspection) through 2017 show that the PTN 10 CFR Part 50, Appendix J AMP has been effectively identifying leaking valves, repairing those valves, and retesting with satisfactory results. The health reports have recently been trending YELLOW with the indication that three or more failed Local Leak Rate Tests (LLRT) within the last three years. The valves were repaired and retested as satisfactory during the refueling outages in which they were identified. The path to a more positive indicator is time based since it takes three years for a test failure to be removed from the rolling list and is expected to be GREEN by November 2018. The failed LLRT are limited to individual unrelated valves that have been promptly corrected and are not indicative of long term system degradation. There have not been any inspections, data review, or work order productivity affecting backlogs or equipment or program health. There are no findings, areas for improvement, violations or Nuclear Electric Insurance Limited issues open.

The program health reports indicate that successful ILRTs were performed on Unit 3 during the 3PT21 refueling outage (2004) and on Unit 4 during 4PT22 (2005). Successful ILRTs were also performed on Unit 3 during the 3PT26 (2012) refueling outage and on Unit 4 during 4PT27 (2013).

The following review of site-specific OE demonstrates how PTN is managing aging effects associated with the PTN 10 CFR Part 50, Appendix J AMP.

1. While performing a scheduled Unit 3 LLRT in November 2015, the as-found leak rate for the nitrogen supply control valve to the accumulators was found to be above the maximum allowed leakage rate. The as-found LLRT results for the valve were entered into the PTN CAP, and the failed LLRT was determined to not be a functional failure. A work order was implemented, and the valve was overhauled. A new as-left LLRT was performed and satisfactory results were acquired prior to entry into Mode 4.

   This example demonstrates that the inspections and tests executed under the PTN 10 CFR Part 50, Appendix J AMP scheduled inspections and the follow-on use of the CAP are effective in evaluating component performance and implementing activities to maintain component intended function.

2. While performing a scheduled Unit 3 LLRT in November 2015 for the fuel transfer flange, the test result was documented to be at the maximum allowed leakage rate value (leakage was documented to be 1100 scc/min which is the maximum allowable leakage for the penetration). Typically, the LLRT results for this penetration are less than

100 scc/min, and the found leakage at the beginning of the outage was 0 scc/min. The leakage rate increase indicated that the flange was installed incorrectly or may have been damaged. A work request was written to initiate a work order to troubleshoot and repair the fuel transfer tube. No additional maximum allowed leakage rate values have been reported for this penetration, and the fuel transfer tube continues to perform its intended function.

This example demonstrates that the PTN 10 CFR Part 50, Appendix J AMP is effective in executing inspections and tests. The CAP not only addresses results that exceed acceptance criteria but also results that are abnormal or have the potential to exceed acceptance criteria. This demonstrates that the PTN 10 CFR Part 50, Appendix J AMP is effective in maintaining component intended function.

3. While performing a scheduled Unit 3 LLRT in November 2015, the as-found leak rate for the vent valve for the containment emergency air lock was found to be above the maximum allowed leakage rate. The condition was entered into the CAP, and a replacement seal kit was installed. Subsequent test results were acceptable. Due to the modifications made to enable accident direction testing (as noted in the OE example below), the valve was tested from the containment side, and this was considered a first time test. Therefore, there are no programmatic concerns. The cause of the valve failure was a worn seat. Additionally, a similar valve in Unit 4 was planned to be tested for the first time in the following outage. Since similar results were expected, rebuild kits were purchased for future repairs. The Unit 4 valve was tested, and results were satisfactory.

   This example demonstrates that the PTN 10 CFR Part 50, Appendix J AMP is effective at anticipating and correcting deficiencies, and that adequate contingency plans are put in place.

4. In July 2015, a review of OE, related to LLRT of the containment airlock inner equalizer valve, determined the LLRT performed at PTN was performed in the reverse direction, and there was no equivalency justification in place at the time to accept that method of testing. After review, PTN determined that the inner (containment side) equalizing or vent valves were not testing in the accident direction for the personnel and escape hatches except during integrated leak rate test (ILRT). In response, PTN performed an evaluation of the penetration in the containment air lock to determine whether testing in the reverse direction is equivalent or satisfactory. For those penetrations which could not show that the reverse testing was equivalent or conservative, modifications to the air lock to enable accident direction testing were implemented.

   This example demonstrates that the PTN 10 CFR Part 50, Appendix J AMP is informed and enhanced when necessary through the systematic and ongoing review of both site-specific and industry OE. Additionally, this example demonstrates that the inspections and tests executed under the AMP scheduled inspections and the follow-on use of the CAP are effective in evaluating degraded component performance and implementing activities to maintain component intended function.

The positive trending of PTN reviews of the AMP, initiation of corrective actions, along with identification and correction of program deficiencies, and subsequent corrective actions prior to loss of intended function, demonstrates that the PTN 10 CFR Part 50, Appendix J AMP remains effective. Additionally, the OE relative to the PTN 10 CFR Part 50, Appendix J AMP provides objective evidence that the existing program will effectively monitor leakage rates through containment systems, its shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings in order to detect degradation of the containment pressure boundary. To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN 10 CFR Part 50, Appendix J AMP, with enhancement, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.34 Masonry Walls

Program Description

The PTN Masonry Walls program is an existing AMP, formerly a portion of the PTN Systems and Structures Monitoring Program. This AMP is a condition monitoring AMP that consists of inspections based on NRC Inspection and Enforcement (IE) Bulletin 80-11 (Reference B.3.50), “Masonry Wall Design,” and NRC Information Notice (IN) 87-67 (Reference B.3.40), “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE 80-11,” for managing shrinkage, separation, gaps, loss of material, and cracking of masonry walls, such that the evaluation basis is not invalidated and that the intended functions are maintained.

The Masonry Walls AMP is a condition monitoring program that provides for inspection of masonry walls for loss of material and cracking through monitoring potential shrinkage and/or separation. The AMP will be enhanced to inspect intake and yard structure masonry walls that are credited for flood protection. The program relies on periodic visual inspections, conducted at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of license renewal so that the established design basis for each masonry wall remains valid during the SPEO. Qualifications of inspection and evaluation personnel are in accordance with the Fleet Engineering Training Program or ACI 349.3R. Unacceptable conditions, when found, are evaluated or corrected in accordance with the CAP.

Masonry walls that are fire barriers are also managed by the Fire Protection (B.2.3.15) program.

NUREG-2191 Consistency

The PTN Masonry Walls AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S5, “Masonry Walls.”

Exceptions to NUREG-2191

None.

Enhancements

The Masonry Walls AMP will be enhanced as follows, to align with NUREG-2191. Enhancements will be completed no later than 6 months prior to the SPEO.

Element Affected	Enhancement
1. Scope of Program	The Masonry Walls program will be enhanced to include the inspection of intake and yard structure masonry walls credited for flood protection.

Operating Experience

Industry Operating Experience

Review for recent industry operating experience did not identify any major issues regarding masonry walls, as informed by the references listed for Masonry Walls (GALL XI.S5) in NUREG-2191.

NRC IN 87-67 documented lessons learned from the NRC IEB 80-11 program and provided recommendations for administrative controls and periodic inspection to provide reasonable assurance that the evaluation basis for each safety-significant masonry wall is maintained. The PTN Masonry Walls AMP incorporates the recommendations delineated in NRC IN 87-67 which provides reasonable assurance that the intended functions of all masonry walls within the SLR are maintained for the SPEO.

Site-Specific Operating Experience

Structures and piping/component support material condition inspections have been performed at PTN since the mid-1980s. The inspection requirements in support of the Maintenance Rule have been in effect since 1996, and have proven effective at maintaining structure and structural component material conditions. Unsatisfactory conditions are detected and resolved through the CAP prior to a loss of intended function.

The effectiveness of the PTN Masonry Walls AMP, formerly a portion of the PTN Systems and Structures Monitoring Program has been demonstrated in the 2012 NRC post-approval site inspection for original licensing renewal (Inspection reports 05000250/2012007 and 05000251/2012007, 05000250/2012008 and 05000251/2012008, 05000250/2012009 and 05000251/2012009) prior to entering the original PEO. These post-approval site inspections identified no observations or findings.

The PTN Masonry Walls AMP is also the subject of periodic internal and external assessments. Quarterly program health reports are developed and trended. These quarterly health reports from 2012 through 2017 indicate that inspections, procedures and plans meet the program requirements. The overall performance of the PTN Structures Monitoring AMP is currently YELLOW with the path to GREEN by 2020 associated with a long-term asset management item and backlog reduction.

The following review of site-specific OE provides examples of how PTN is managing aging effects associated with the PTN Masonry Walls AMP. This AMP is supplemented by the PTN Structures Monitoring AMP (Section B.2.3.35).

1. In June of 2013, a crack was identified during a walkdown in a wall south wall of the 3A switchgear load center room which is located in the turbine building. The wall is a safety-related masonry wall and also serves as a fire barrier and is inspected every 18 months. The crack was determined to be caused by the differential vibration between

the turbine pedestal and the block wall. This same crack was identified previously in 2005 and dispositioned in the CAP based on an engineering evaluation that no repairs were warranted. The crack has continuously been trended in the CAP since 2005, and there has been no noticeable change in the size of the crack. The crack was verified in 2013 to be less than the procedural acceptance criteria of $\leq$ 1/16 inch in width.

2. In August 2012, age-related deficiencies in the perimeter flood protection barrier were discovered as part of the NEI 12-07 Verification Walkdown of Plant Flood Protection Features (Fukishima Flooding Walkdown). Various deficiencies were observed including cracks, spalling/popouts, and holes in concrete masonry unit (CMU) flood barrier walls. None of the issues were determined to challenge the ability of the perimeter flood wall to perform its function as an external flood protection barrier. However, if left uncorrected, the deficiencies had the potential to degrade further and challenge the functionality of the barrier. A work request and follow-on work order were initiated which repaired the CMU wall. Structures Monitoring Program walkdowns were completed in 2017 with no further issues identified.

3. In June 2011, minor damage to portions of the flood wall at the entry of the turbine building were discovered. The damage did not prevent the installation of the flood gate. A work request was initiated to evaluate the flood wall and repair it as necessary. Design Engineering performed a walkdown of the affected area. As inspected, the subject wall was determined to continue to perform its intended function. However, in order to restore the wall to original design requirements, a work order was initiated to perform minor repairs to the wall. Structures Monitoring Program walkdowns were completed in 2017 with no further issues identified.

As stated in Section B.1.1, the PTN Masonry Walls AMP for the SPEO is associated with the PTN Systems and Structures Monitoring Program that is credited in the PEO, as masonry walls are included in the structural walkdowns performed through that program. The PTN Systems and Structures Monitoring Program was found to be ineffective by the most recent AMP effectiveness assessment. This ineffectiveness is addressed in the Structures Monitoring AMP (Section B.2.3.35) and the External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23). As such, there is reasonable assurance that the PTN Masonry Walls AMP will manage the effects of aging through the SPEO to ensure that intended functions are maintained.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. Corrective actions have been initiated and completed to resolve AMP issues regarding the identified ineffectiveness of the Systems and Structures Monitoring AMP. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN Masonry Walls AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.35 Structures Monitoring

Program Description

The PTN Structures Monitoring AMP, formerly a portion of the PTN Systems and Structures Monitoring Program, is an existing AMP that manages the aging effects of loss of material, cracking, fouling, loss of seal, and change in material properties, and provides assurance that structures and structural components within the scope of SLR will not degrade to the point of loss of component intended function during the SPEO. This AMP provides for periodic visual inspection, by qualified personnel, and examination for degradation of accessible surfaces of specific SSCs (including condition of concrete and steel structures, structural components, component supports, and structural commodities). Corrective actions are performed as required based on these inspections.

Implementation of structures monitoring is required under 10 CFR 50.65 (the Maintenance Rule) and is addressed in NRC RG 1.160 (Reference B.3.27), “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and Nuclear Management and Resources Council (NUMARC) 93-01 (Reference B.3.88), “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

The PTN Structures Monitoring AMP consists primarily of periodic visual inspections by personnel qualified to monitor structures and components for applicable aging effects from degradation mechanisms, such as those described in the ACI 349.3R-02 (Reference B.3.118), “Evaluation of Existing Nuclear Safety-Related Concrete Structures,” ACI 201.1R-08 (Reference B.3.116), “Guide for Conducting a Visual Inspection of Concrete Service,” and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11-99 (Reference B.3.121), “Guideline for Structural Condition Assessment of Existing Buildings.” Identified aging effects are evaluated by qualified personnel using criteria derived from industry codes and standards contained in the plant CLB including but not limited to ACI 349.3R, ACI 318 (Reference B.3.117), SEI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications, as applicable.

Concrete surfaces are inspected for cracking, scaling, spalling, pitting, erosion, corrosion of reinforcing bars, settlement, deformation, leaching, discoloration, groundwater leakage, rust stains, exposed rebar, rust bleeding, and other surface irregularities. Structural steel is inspected for loss of material (corrosion), deflection, and distortion. Bracing connections associated with masonry walls are also inspected for degradation. The PTN Structures Monitoring AMP inspects accessible sliding surfaces for indication of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. Loose, missing, or damaged anchor bolts are visually inspected. High-strength bolts are visually inspected. Each structure's foundation is monitored for overall settlement and differential settlement. Structures are monitored to confirm the absence of water in-leakage or signs of concrete leaching, chemical attack or steel reinforcement degradation. Elastomers will be inspected for signs of hardening.

A dewatering system is not used or part of the CLB for PTN. Structures are monitored to confirm the absence of water in-leakage or signs of concrete leaching, chemical attack or steel reinforcement degradation. Due to the presence of high chloride levels in the groundwater a site-specific enhancement to manage the concrete aging during SPEO will include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years.

This AMP includes preventive actions to ensure structural bolting integrity. Proper selection of bolting material, appropriate installation torque or tension, lubricant selection, and bolting material selection are emphasized.

Concrete structures at PTN were designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix used Portland cement conforming to ASTM C-150-64, Florida Type II. Also the cement contains no more than 0.60 percent by weight of total alkalis which prevents harmful expansion due to alkali aggregate reaction. Concrete aggregates conformed to the requirements of ASTM C-33-64 (fine and coarse aggregate) and conformed to the requirements of ASTM C33, “Standard Specification of Concrete Aggregates.” Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment and organic matter. Materials for concrete used in PTN concrete structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards at the time of construction. However, this testing did not fully conform to ASTM C295 specified in NUREG-2192 and therefore, cracking due to expansion and reaction with aggregates, including alkali silicate reactions (ASR), is an applicable aging effect in concrete for PTN. PTN operating experience does not indicate issues of cracking due to ASR or dimensional expansions affecting PTN structures, but to provide additional direction on detecting this potential aging effect the implementing procedures will be enhanced to include specific directions with respect to inspections for signs of cracking and expansion due to reaction with aggregates in concrete structures.

NUREG-2191 Consistency

The PTN Structures Monitoring AMP, with exception and enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S6, "Structures Monitoring."

Exceptions to NUREG-2191

The PTN Structures Monitoring AMP takes an exception to the groundwater and soil testing recommended by NUREG-2191.

The groundwater/soil at PTN is aggressive (chlorides > 500 ppm). Since the chloride levels for seawater are much greater than 500 ppm, there is reasonable certainty that any groundwater/soil chemistry tests will consistently result in chloride level readings that are greater than 500 ppm which indicates an aggressive groundwater/soil classification, and periodic sampling and testing is not necessary and of little value. Rather, the PTN Structures Monitoring AMP includes a site-specific enhancement to address aggressive groundwater soil, that may include evaluations, destructive testing if warranted, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, based on site OE but not to exceed 5 year intervals.

Enhancements

The PTN Structures Monitoring AMP will be enhanced as follows, for alignment with NUREG-2191. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope	Update the governing AMP procedure to add the following components and commodity groups to the list of inspected items: • Fan/filter intake hood (Auxiliary Building) • Pipe trench penetration and fire seals used for flood protection • Stop logs • Doors (Diesel Driven Fire Pump Enclosure) • Louvers (Diesel Driven Fire Pump Enclosure) • HVAC roof hoods (Emergency Diesel Generator Building) • Louvers (Emergency Diesel Generator Building) • U4 Diesel Oil Storage Tank liner • Electrical Enclosures (Intake Structure) • Structural Truck Bridge (Intake Structure) • New Fuel Storage Components • NaTB sump fluid pH control basket • Drains, drain plugs (stored in various locations) that are credited for external flood protection • Berms and paved ramps that are credited for external flood protection
2. Preventive Actions	Update the pertinent AMP specification to include the preventive action requirements for proper storage of high strength bolts.
3. Parameters Monitored or Inspected	Update the governing AMP procedure to include the monitoring of loss of material, loose bolts, missing or loose nuts, and other conditions that indicate loss of preload. Update the governing AMP procedure with a minor editorial change to include SEI/ASCE 11 (Reference B.3.121) and AISC in the references section to account for any design parameters used for evaluation.

Element Affected	Enhancement
4. Detection of Aging Effects	Update the governing AMP procedure with a site-specific enhancement that may include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. The respective evaluation/inspection/ testing interval is not to exceed 5 years. Update the governing AMP procedure with guidance on monitoring for indications of cracking and expansion due to reaction with aggregates in concrete structures. Update the governing AMP procedure to clarify that tactile inspection may be needed for detection of elastomer hardening.
6. Acceptance Criteria	Update the governing AMP procedure to state that loose bolts and nuts are not acceptable unless accepted by an engineering evaluation. Update the governing AMP procedure acceptance criteria to state that structural sealants are not acceptable unless the observed loss of material, cracking, and hardening will not result in loss of sealing.

Operating Experience

Industry Operating Experience

External (industry) operating experience is evaluated through the AR process to confirm applicability to PTN and identify the appropriate adjustments/improvements to the pertinent AMP(s), if any. For example:

- Information Notice (IN) 2011-20 describes an instance of groundwater infiltration leading to ASR degradation in below-grade concrete structures.

  PTN evaluated the preliminary and subsequent operating experience on this topic, with no evidence of degradation of PTN concrete. PTN continues to follow this issue through the condition report of another plant (Seabrook) in the fleet. Additionally, PTN will enhance the PTN Structures Monitoring AMP as described above to include guidance on monitoring for indications of cracking and expansion due to reaction with aggregates as well as exposure to aggressive groundwater/soil.

- IN 2006-13 addresses nine issues relative to groundwater contamination (tritium), one of which is spent fuel pool leakage. Spent fuel pool leakage is also addressed in IN 2004-05.

This operating experience has been evaluated at the fleet level. As described in Table 3.5.2-15, PTN monitors spent fuel pool water level and leakage from leak chase channels. Instances of minor spent fuel pool liner leakage have been identified, evaluated to ensure no loss of intended function, and cleaned up (housekeeping). Spent fuel pool leakage has not resulted in groundwater contamination.

Site-Specific Operating Experience

Structures and piping/component support material condition inspections have been performed at PTN since the mid-1980s. The inspection requirements in support of the Maintenance Rule have been in effect since 1996, and have proven effective at maintaining structure and structural component material conditions. Unsatisfactory conditions are detected and resolved through the CAP prior to a loss of intended function. There have been no instances of degraded sliding surfaces for components in the scope of SLR. While the PTN Structures Monitoring AMP inspects for settlement and differential settlement as described above, there have been no occurrence of settlement at PTN, as described in Sections 3.5.2.2.1.1 and 3.5.2.2.2.1. Elastomer seal degradation has been identified and corrected through visual inspections. The PTN Structures Monitoring AMP will be enhanced to include tactile inspection of elastomeric materials for detection of hardening.

The Systems and Structures Monitoring Program operating experience, from renewed license issuance in June 2002 to entering the PEO in 2012, is described in inspection notebooks compiled in support of the 2012 NRC post-approval site inspections (Inspection reports 05000250/2012007, 05000250/2012008, 05000251/2012008, 05000250/2012009, and 05000251/2012009).

The March, July and December 2012 post-approval NRC inspections each addressed some aspect of the Systems and Structures Monitoring Program and concluded that:

- License renewal commitment, to restructure the program to address inspection requirements to manage certain aging effects, modify the scope of specific inspections and improve documentation requirements (procedures associated with this PEO enhancement are cited in UFSAR Section 16.3.7, had been implemented;

- Aging management of structural components that were inaccessible for inspection was accomplished by inspecting accessible structural components with similar materials and environments for aging effects that may be indicative of aging effects for the inaccessible structural components;

- The essential attributes of Spring 2012 RFO examinations, such as calibration and disposition of indications, were performed in accordance with the license renewal commitment;

- Program was implemented in accordance with the license renewal application and NRC safety evaluation report (NUREG-1759) and in-scope structural walkdowns were completed prior to the PEO for Unit 3; and
- There is reasonable assurance that FPL would adequately manage the aging effects associated with the Systems and Structures Monitoring Program and continue it during the PEO.

The PTN Structures Monitoring AMP is also the subject of periodic internal and external assessments. Quarterly PTN Structures Monitoring AMP health reports are developed and trended. Program health reports from 2012 to present indicate that inspections, procedures and plans meet the program requirements. The overall performance of the PTN Structures Monitoring AMP is currently YELLOW with the path to GREEN by 2020 associated with a long-term asset management items and backlog reduction effort.

Identified backlogged items are degraded concrete and structural steel conditions that do not require near-term corrective action, but warrant future attention, and repair. These conditions have been noted, evaluated and determined to have no loss of intended function, with work orders issued. The most significant of these include:

1. The auxiliary building is considered to be functional but degraded and a Maintenance Rule (MR) (a)(1) structure. Repair activities started in 2014 to address seven internal wall or floor locations at various elevations with identified concrete degradation, such as cracked plaster in stairwells. Engineering changes and repairs were completed for three of the seven locations in 2015, including excavation and repair of spalled concrete, with the remaining four items addressed through the CAP and currently scheduled for resolution by the end of 2020.
2. The Unit 3 spent fuel building is also considered to be functional but degraded, with the Unit 4 spent fuel building showing signs of degradation. Spalling and exposed reinforcement on exterior walls above the water level in the spent fuel pit have been identified and evaluated relative to external and internal loading and water loss with the determination that there has been no loss of function. The issue is being addressed through the CAP and currently scheduled for resolution by the end of 2020.
3. The Unit 3 and Unit 4 intake structures have bays that are operable but degraded, with ICW pump slab reinforcing steel beams which evidence corrosion that warrants removal/repair prior to recoating. Two of the six bays were repaired and recoated in 2016, as described for the PTN Inspection of Water Control Structures Associated with Nuclear Power Plants AMP (Section B.2.3.36).

Examples of structural areas where degradation has been effectively identified, evaluated, and repaired include the turbine building, and plant vent stack:

1. In 2015, pieces of concrete and corroded rebar were determined to be falling from the turbine deck to the mezzanine near the penetration at the ceiling where the steam pipes go to the turbine deck. Nearby areas of the ceiling and turbine deck were inspected and determined that degradation was localized and there was no concern with structural integrity of the turbine deck. Instrumentation and equipment were not adversely affected in the area congested with steam piping and relatively low ceiling. It was also determined there was no immediate concern for personnel safety, as long as individuals entering the area were wearing required personal protective equipment (PPE). As a precaution, the area was marked to warn of the falling and loose concrete. The 2015 condition is bounded by an apparent cause evaluation (ACE), for concrete spalling from the bottom side of the turbine deck, performed in 2007. The 2015 evaluation agreed with the ACE conclusion, in that the condition does not present a significant structural concern and repairs should be performed in a timely manner to prevent additional corrosion and material loss of the exposed rebar. Work orders were issued and Plant Engineering continued to monitor the condition of the structure every 18 months until repairs were completed in late 2016.

2. Water intrusion issues into the switchgear/load center rooms, which are located in the turbine building, have been an ongoing issue at PTN. As part of the long-term asset management program at PTN, a specific action item was generated to track and perform a remediation. The issue was partially corrected in 2014 by applying a roofing system to the impacted areas, with follow-up actions and repair completed in the fourth quarter of 2015 for Unit 4 and in the first quarter of 2016 for Unit 3. To date, there has been no recurrence of water intrusion into the switchgear / load center rooms since post-modification confirmation of the roofing system.

3. Degradation of the plant vent stack was reported in 2003. In 2007, the plant vent stack cat walk was determined to be unsafe for personnel use. In 2009, a plant operability determination was performed and concluded that the plant vent stack was capable of withstanding design basis loads. In 2010, the plant vent stack was determined to have low margin. In 2012, the plant vent stack was determined to be a nonconformance. Further inspection and evaluation were performed through the CAP. Contingency shoring (cable/rope) was installed for the plant vent stack in preparation for inclement weather and to ensure that the structure could sustain design basis events prior to work order completion. The corroded platform was repaired and the structure restored to original design condition in 2013.

As stated in Section B.1.1, the System and Structures Monitoring Program, credited for the PEO, was found to be ineffective in the December 2017 PTN License Renewal AMP Effectiveness Review. At PTN, the Systems and Structures Monitoring AMP is treated as two separate AMPs. The Structures sub-part of the AMP will be discussed here, since it is most associated with the Structures Monitoring AMP which will be credited for the SPEO. The Structures sub-part of the AMP failed Element 2, Preventive Actions, Element 4, Detection of Aging Effects, and Element 7, Corrective Actions. Failed elements were due to the deficiencies listed below, with the associated resolutions also described:

a. Scheduled Unit 3 walkdowns had not been completed within the 5-year interval. The Unit 3 walkdowns that had exceeded the 5-year interval were completed in December 2017. The evaluation of these walkdowns results concluded there would be no loss of function prior to the next scheduled inspection.

b. Follow-up inspections for evidence of correction of degradation were not tracked to completion. Follow-up inspections were completed in December of 2017. The evaluation of these follow-up inspections concluded that the lack of inspections did not result in component loss of function.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. As described, corrective actions have been initiated and completed to resolve AMP issues regarding the identified ineffectiveness of the Systems and Structures Monitoring AMP. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN Structures Monitoring AMP, with an exception and enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.36 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The PTN Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing program, formerly a portion of the PTN Systems and Structures Monitoring Program. The AMP manages age-related degradation due to environmental conditions, and the effects of natural phenomena that may affect water-control structures, through periodic monitoring and maintenance activities.

The NRC RG 1.127 (Reference B.3.24), "Inspection of Water-Control Structures Associated with Nuclear Power Plants," provides detailed guidance for an inspection program for water-control structures, including guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports. NRC RG 1.127 delineates the current NRC practice for evaluating inspection and surveillance programs for water-control structures. Although PTN has not formally committed to implement RG 1.127, this AMP addresses inspection of water-control structures, commensurate with RG 1.127.

The scope of the PTN Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP includes the Intake Structure, Discharge Structure, and Cooling Canals. The scope of this AMP also includes structural steel, and structural bolting associated with water-control structures, and miscellaneous steel. Coatings on structures within the scope of this AMP are inspected only as an indication of the condition of the underlying material. PTN has no sliding surfaces or wooden components associated with water-control structures or dams that require aging management.

This AMP is a conditioning monitoring program. The AMP includes preventive actions to provide reasonable assurance for structural bolting integrity as discussed in ASTM and AISC specifications, as applicable. 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 high-strength bolting. The parameters monitored, inspected, and assessed by this AMP, for concrete structures, are those described in ACI 201.1R-08 (Reference B.3.116) and ACI 349.3R-02 (Reference B.3.118). These parameters include cracking, movements (e.g., settlement, heaving, and deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage.

Parameters monitored for canals will be enhanced to include erosion, degradation, silting or unwanted vegetation that may impose constraints on the function of the cooling system. In-scope steel components are monitored for loss of material due to corrosion. Painted or coated areas are examined for signs of distress that could indicate degradation of the underlying material. Bolting within the scope of the program is monitored for loss of material, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. In addition, concrete around anchor bolts is monitored for cracking. High strength bolts within the scope of the program are visually inspected. Indications of groundwater infiltration or through-concrete leakage are assessed for aging effects.

Inspections of water-control structures by this AMP are conducted under the direction of qualified engineers experienced in the investigation, design, construction, and operation of these types of facilities. Qualifications of inspection and evaluation personnel for reinforced concrete water control structures are in accordance with ACI 349.3R. Visual inspections are primarily used to detect degradation of water-control structures. Periodic inspections are performed at least once every 5 years. The AMP includes provisions for increased inspection frequency based on an evaluation of the observed degradation. The AMP also includes provisions for special inspections immediately following major unusual events such as hurricanes, floods, or seismic events.

From comparison with the chloride level for seawater, the groundwater/soil at PTN is considered aggressive (chlorides > 500 ppm). Therefore, PTN will perform a focused inspection of below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years. Submerged concrete structures may be inspected during periods of low tide, when dewatered or using divers. Areas covered by silt, vegetation, or marine growth are not considered inaccessible and are cleaned and inspected in accordance with the standard inspection frequency.

Results from the periodic inspections associated with this AMP are documented and compared to previous results to identify changes from prior inspections.

Photographs properly annotated showing the overall condition of each area, including areas with deficiencies, are used to document the findings and used to trend the degradation. The baseline (initial) inspection(s) of each structure are documented in inspection reports maintained as part of this AMP.

NUREG-2191 Consistency

The PTN Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Update the governing AMP procedure to include the Reinforced Concrete Shield Wall for the Discharge Structure in the list of components inspected.
2. Preventive Actions	Update the pertinent AMP specification to include the preventive action requirements for proper storage of high strength bolts.
3. Parameters Monitored or Inspected	Update the governing AMP procedure to include the monitoring of loss of material, loose bolts, missing or loose nuts, and other conditions that indicate loss of preload. Update the governing AMP procedure to monitor for increases in porosity and permeability, and conditions at junctions with abutments and embankments.
4. Detection of Aging Effects	Update the governing AMP procedure to include focused inspections of below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years. Update the governing AMP procedure to include inspection of cooling canals for siltation or undesirable vegetation that could impair the cooling canal function.
6. Acceptance Criteria	Update the governing AMP procedure to state that loose bolts and nuts are not acceptable unless accepted by engineering evaluation.

Operating Experience

Industry Operating Experience

Degradation of water-control structures has been detected, through NRC RG 1.127 programs, at a number of nuclear power plants, and, in some cases, it has required remedial action. NRC NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures," described instances and corrective actions of severely degraded steel and concrete components at the intake structure and pump house of coastal plants. Other forms of degradation described in the NUREG include appreciable leakage from spillway gates, concrete cracking, corrosion of spillway bridge beam seats of a plant dam and cooling canal, and appreciable differential settlement of the outfall structure. No loss of intended functions has resulted from these occurrences. Therefore, it can be concluded that the inspections implemented in accordance with the guidance in NRC RG 1.127 have been successful to date in detecting significant degradation before loss of intended function occurs.

Site-Specific Operating Experience

Structures and piping/component support material condition inspections have been performed at PTN since the mid-1980s. The inspection requirements in support of the Maintenance Rule have been in effect since 1996, and have proven to be generally effective at maintaining structure and structural component material conditions. Unsatisfactory conditions are detected and resolved through the CAP prior to a loss of intended function.

The effectiveness of the PTN Inspection of Water-Control Structures AMP, formerly a portion of the PTN Systems and Structures Monitoring Program, has been demonstrated in inspection notebooks compiled in support of the March, July and December 2012 NRC post-approval site inspections (Inspection reports 05000250/2012007 and 05000251/2012007, 05000250/2012008 and 05000251/2012008, 05000250/2012009 and 0500025cc1/2012009) conducted prior to entering the original PEO. This post-approval NRC site inspection identified no observations or findings regarding this AMP.

The PTN Inspection of Water-Control Structures AMP, formerly a portion of the PTN Systems and Structures Monitoring Program, is also the subject of periodic internal and external assessments. Quarterly PTN Structures Monitoring health reports, which include Inspection of Water-Control Structures, are developed and trended. Program health reports from 2012 to present indicate that inspections, procedures and plans meet the program requirements. The overall performance of the PTN Structures Monitoring AMP is currently YELLOW with the path to GREEN anticipated by 2020 associated with a long-term asset management items and backlog reduction effort.

Identified backlogged items are degraded concrete and structural steel conditions that do not require near-term corrective action but warrant future attention, and repair. These conditions have been noted, evaluated and determined to have no loss of intended function pending further action, with work orders issued. The most significant of these include:

1. As noted in the 2012 Structures Monitoring Program system health report, there was a high number of backlogged corrective action maintenance items for the U4 Intake Structure Cathodic Protection System repairs that were open for more than six months. The intake structure was considered to be functional but degraded and a Maintenance Rule (MR) (a)(1) structure until the third quarter of 2014 due to corrosion issues. The Maintenance Rule walkdowns were subsequently completed according to the program timeline.

2. In 2013, degraded coatings on steel beams supporting the ICW pump slabs at the Unit 3 and 4 Intake Structure and degraded material condition of the discharge structure were identified. A 2016 prompt operability determination (POD) declared the Unit 3 and 4 ICW pump bays operable but degraded until steel repairs were performed. In the third and fourth quarter of 2016, ICW pump slab reinforcing steel beam repairs were performed on

two Unit 4 intake bays prior to re-coating. This condition (corrosion requiring steel repairs and recoating) exists in the remaining four intake bays that support ICW pumps. Repair of the remaining four bays are being addressed through the CAP and are currently scheduled for completion during 2019/2020.

3. Some examples of structural areas where degradation has been identified, evaluated, and repaired include the Intake Well, and Intake Structure:

4. In May of 2016, while performing preparation activities for coating repairs, pitting and degradation was found on the ICW Piping and structural steel and plates in an Intake Well as well as degradation of the existing beam supports on the Intake Structure. It was noticed that some areas of the intake structure presented significant through-wall corrosion. At one location, there was complete loss of portions of the flange and web near the end connection of the beam. A POD was performed to determine that no adverse impact exists on the plant system as a consequence of the as found steel deterioration. The POD evaluation was performed to verify the structure remains operable and concluded that the degraded condition did not prevent the structure from performing its design function. A work order was initiated for repairs. The structure was inspected every 30 days until it was repaired in September 2016.

   As part of the May 2016 walkdowns, a nonconformance report documenting spalled concrete and deteriorated reinforcing steel in the concrete slab supporting the ICW pump in the intake structure was identified, degrading its ability to support vertical loading. A POD was performed to confirm operability of the structure. At one location, there was complete loss of portions of the flange and web near the end connection of the T-beam. Work orders were provided to repair the degraded condition and restore margin to the structural support. Appropriate corrective actions were taken to correct the condition and restore design margin. In order to correct this deficiency and to restore the vertical capacity of the slab, a composite plate design was added to the bottom part of the slab after all spalled concrete was chipped away and replaced.

5. In October of 2016, housekeeping walkdowns of the Intake Structure identified that degraded coatings had resulted in poor material condition of some equipment and supports. The observations were not associated with coatings restoration work in the intake bays but rather were associated with the material condition of the equipment and supports mounted on the structure. Unsatisfactory conditions were detected and resolved through the CAP prior to a loss of intended function. Work orders were provided to repair the degraded conditions of the equipment and structural supports. Appropriate corrective actions were initiated to correct the condition and restore design margin.

As stated in Section B.1.1, the PTN Inspection of Water Control Structures Associated with Nuclear Power Plants AMP for the SPEO is associated with the PTN Systems and Structures Monitoring Program that is credited in the PEO, as water control structures are included in the structural walkdowns performed through that program. The PTN Systems and Structures Monitoring Program was found to be ineffective by the most recent AMP effectiveness assessment. This ineffectiveness is addressed in the Structures Monitoring AMP (Section B.2.3.35) and the External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23). As such, there is reasonable assurance that the PTN Inspection of Water Control Structures Associated with Nuclear Power Plants AMP will manage the effects of aging through the SPEO to ensure that intended functions are maintained.

PTN is actively implementing and managing its AMPs overall and seeking to identify areas that would improve the effectiveness of aging management. Corrective actions have been initiated and completed to resolve AMP issues regarding the identified ineffectiveness of the Systems and Structures Monitoring AMP. As an extent of condition, the latest AMP effectiveness assessment requires all AMP owners to review the assessment findings and take corrective action, as necessary, to resolve any similar weaknesses. In addition, AMP effectiveness for this AMP will be re-assessed in 2018 per NEI 14-12.

Conclusion

The PTN Inspection of Water-Control Structures AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.37 Protective Coating Monitoring and Maintenance

Program Description

The PTN Protective Coating Monitoring and Maintenance AMP is an existing AMP, formerly the PTN Service Level I Coatings Program, although it was not previously credited for license renewal. This AMP consists of guidance for selection, application, inspection, and maintenance of the Service Level I protective coatings inside the PTN Unit 3 and Unit 4 reactor containment buildings, on both steel and concrete substrates. Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors) serve to prevent or minimize loss of material due to corrosion of carbon steel components and aids in decontamination. Degraded coatings in the containment are assessed periodically to ensure post-accident operability of the emergency core cooling systems (ECCS).

Proper maintenance of protective coatings inside containment (defined as Service Level I in the NRC RG 1.54 (Reference B.3.20), "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants") is essential to the operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of ECCS suction strainers, which reduces flow through the system and could cause unacceptable head loss for the pumps. Regulatory Position C4 in NRC RG 1.54 describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program. ASTM D 5163-08 (Reference B.3.127) and endorsed years of the standard in NRC RG 1.54 are acceptable and considered consistent with NUREG-2191, Section XI.S8. EPRI-1019157 (Reference B.3.101), "Guideline on Nuclear Safety-Related Coatings," provides additional information on the ASTM standard guidelines. Service Level I coatings are design features which serve to minimize corrosion of steel liners for concrete containments that are subject to requirements specified by the PTN ASME Section XI, Subsection IWE AMP (Section B.2.3.30).

The PTN Protective Coating Monitoring and Maintenance AMP is a condition monitoring program, with scope that includes Service Level I coatings inside PTN Unit 3 and Unit 4 reactor containment buildings on both steel and concrete substrates. Per the PTN ASME Section XI, Subsection IWE AMP (Section B.2.3.30), coatings are a design feature of the base material and are not credited with managing loss of material.

The PTN Protective Coating Monitoring and Maintenance AMP provides guidelines for establishing an inservice coatings monitoring program for Service Level I coating systems in accordance with ASTM D 5163-08 (Reference B.3.127). The AMP will use the aging management detection methods, inspection frequency, monitoring and trending, and acceptance criteria defined in ASTM D 5163-08 (Reference B.3.1275), "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants," and inspect for any visible defects, such as blistering, crazing, cracking, flaking, peeling, rusting, and physical damage. The inspection frequency is to be each refueling outage (RFO) or during other major maintenance outages, as needed. The areas to be inspected and inspection priorities are based on the impact of potential coating failures on plant safety (e.g., proximity to the ECCS sump), previously identified problems, unqualified coatings, and areas subject to higher corrosion rates. The inspection report should prioritize repair areas as either needing repair during the same outage or as postponed to future outages, but under surveillance in the interim period. The assessment from periodic inspections and analysis of total amount of degraded coatings in the containment is compared with the total amount of permitted degraded coatings to provide reasonable assurance of ECCS operability. Individuals performing the inspections shall be trained in accordance with ASTM D5498.

ASTM D 5163-08 (Reference B.3.127), subparagraphs 10.2.1 through 10.2.6, 10.3, and 10.4, contains one acceptable method for the characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting. ASTM D 5163-08, paragraph 11, addresses evaluation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, and prioritization of repairs.

NUREG-2191 Consistency

The PTN Protective Coating Monitoring and Maintenance AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S8, “Protective Coating Monitoring and Maintenance.”

Exceptions to NUREG-2191

None.

Enhancements

The PTN Protective Coating Monitoring and Maintenance AMP will be enhanced as follows, for alignment with NUREG-2191. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Update the pertinent AMP specification to reference and use the guidance of ASTM D 5163-08 (Reference B.3.127).
4. Detection of Aging Effects	Update the pertinent AMP specification to state that individuals performing that inspection shall be trained in the applicable reference standards of ASTM D5498 (Reference B.3.128).

Element Affected	Enhancement
6. Acceptance Criteria	Update the pertinent AMP specification to include the specific inspection and documentation parameters listed in ASTM D 5163-08 (Reference B.3.127) subparagraph 10.2.1 through 10.2.6, 10.3, and 10.4.
6. Acceptance Criteria	Update the pertinent AMP specification to include the observation and testing methods listed in ASTM D 5163-08 (Reference B.3.127) subparagraphs 10.2.3 and 10.2.4.
10. Operating Experience	Update the pertinent AMP specification to be in accordance with the guidance of Regulatory Position C4 of RG 1.54 (Reference B.3.20) Revision 2.

Operating Experience

Industry Operating Experience

The PTN Protective Coating Monitoring and Maintenance AMP considers the best practices of industry organizations, vendors, utilities, and protective coatings experts. This is accomplished through effective monitoring of key parameters with well-defined acceptance criteria per the guidance given in RG 1.54.

Generic Safety Issue (GSI) 191 concerns, including those related to coatings and sump strainer blockage, have been addressed in FPL responses and actions since 2008. The industry OE from the related communications have been factored into the site programs, including the PTN Protective Coatings Monitoring and Maintenance AMP. GSI-191 is an open issue for PTN that is being addressed on an ongoing basis. If there are any changes to the PTN Protective Coatings Monitoring and Maintenance AMP that result from updating the PTN response to Generic Letter 04-02, Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors, they will be addressed in the annual update of the SLRA.

Site-Specific Operating Experience

This AMP is subject to periodic internal and external assessments that help to maintain highly effective coating quality and facilitate continuous improvement. Containment coating inspections are performed at the end of each refueling outage. The Nuclear Coating Specialist determines the areas to be inspected and the inspection priorities based on the impact of coating failures on plant safety (e.g., proximity to the ECCS sump), previously identified problems, unqualified coatings, and areas subject to higher corrosion rates. Factors such as availability and accessibility to coated equipment and surfaces, as well as ALARA considerations, are factored into the prioritization process. Field notes document the approximate location and square footage of identified deteriorated and unqualified coatings which have not been removed, and which do not require removal prior to startup. Based on ECCS strainer design requirements as documented in plant calculations, a permissible limit of 4.17 cubic feet of unqualified coatings (i.e., 2500 square feet with an assumed thickness of 20 mils) is established for the Reactor Containment Building (RCB). This limit applies to all unqualified coatings and loose or peeling coatings within the RCB, with the exceptions of the unqualified coatings on the Reactor Coolant Pump (RCP) motors and stands, the zinc coatings applied to HVAC duct joints and the Thermalux coating applied to uninsulated steel piping.

The CAP is used to document and correct the findings, and the coatings specification is revised to include them. Adhesion tests are performed when defects are identified. Repairs are prioritized based on proximity to the sump and extent of corrosion. Items to be coated are identified in the unqualified coatings log. Corrosion control and foreign material exclusion (FME) control consists of multiple walkdowns and inspections, including inspections of coatings inside containment. While performing inspection activities, the following conditions were identified:

1. On November 10, 2015, the amount of unqualified coating was determined to be increased by 0.0338 cubic feet to a total of 1.29 cubic feet. The total volume of unqualified coatings is below the limits specified in the coating specification and was determined to be acceptable.

2. On October 26, 2015, paint/coatings over the Unit 3 reactor cavity were inspected and found to be unsatisfactory due to both the internals stand and lift rig coatings demonstrating lifting, blistering, cracking, and peeling. Multiple paint chips and debris identified on the lower cavity floor. Large sections appear ready to flake off. Unsatisfactory conditions are detected and resolved through the CAP prior to a loss of intended function. The coatings specification already includes direction for inspection of various SSCs which have the potential of having loose or peeling coatings that could fall into the reactor cavity. The specification also requires that loose or peeling coatings to be removed to the extent practical prior to flood-up of the cavity. Although all of the loose coatings were not removed, at the time it was considered to be a "best effort" as performed by radiation protection under the circumstances. A suitable window for performing additional scraping was not identified during the remainder of the same outage. This was deemed acceptable because the cavity will not be flooded again until after the next opportunity to perform the scraping during the following refueling outage. The loose and peeling coatings appeared to be caused by normal age-related degradation of the existing coatings. In the case of coatings peeling from stainless steel items, these did not require coatings and may have been inadvertently coated during previous coatings activities. Paint scraping and/or recoating is performed in accordance with the coating specification and is performed each refueling outage. Because these activities were already included in the specification and addressed by a prior ACE, additional corrective actions were not considered necessary for this finding.

3. On October 26, 2015, paint/coatings over the Unit 3 reactor cavity were inspected and found to be unsatisfactory due to both the internals stand and lift rig coatings demonstrating lifting, blistering, cracking, and peeling. Multiple paint chips and debris were identified on the lower cavity floor, and large sections appeared ready to flake off.

The loose and peeling coatings appeared to be caused by normal age-related degradation of the existing coatings. The coatings specification includes direction for inspection of various SSCs which have the potential of having loose or peeling coatings that could fall into the reactor cavity. The specification also requires that loose or peeling coatings be removed to the extent practical each refueling outage prior to flood-up of the cavity. A suitable window for performing additional scraping was not identified during the remainder of the same outage. Consistent with the specification, this was deemed acceptable because the cavity will not be flooded again until after the next opportunity to perform scraping during the following refueling outage. Because these activities were already included in the specification and addressed by a prior ACE, additional corrective actions were not considered necessary for this finding. In the case of coatings peeling from stainless steel items, these did not require coatings and may have been inadvertently coated during previous coatings activities.

4. On November 16, 2015, deteriorated coatings were identified on the CCW piping inside the Unit 3 containment in the wall penetration between zone 1 and zone 2, outside the biowall on the 14-ft. elevation. This location was compared with another location with the same piping system but CCW for "A" RCP thermal barrier and it was concluded that the condition on both pipes is very similar. The main driver for the indications observed on both locations is coating failure/degradation (i.e. blisters and surface corrosion). UT was performed on the "A" related piping to determine remaining wall thickness, and it was determined that the line was acceptable. Considering that the environmental and operating conditions are very similar, it was concluded by inspection and comparison that the CCW line identified (CCW to "C" RCP thermal barrier) is acceptable for at least one cycle. A prompt operability determination performed by Engineering concluded that the subject CCW piping was operable and fully qualified with reduced margin. A work order was generated and completed to clean and coat the subject piping. Paint scraping and/or recoating is performed in accordance with the coating specification.

The above examples provide objective evidence that the AMP is capable of both detecting and trending the aging effects of protective coatings for Service Level I Application inside the PTN Reactor Containment Building. A review of the operating experience examples showed that, where age-related degradation has been identified, the appropriate measures have been taken or specified to prevent loss of intended function. The CAP is constructively used to take effective corrective measures prior to loss of component intended function. Conditions identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. To date, no enhancements to the AMP have been identified as a result of OE. However, OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Protective Coating Monitoring and Maintenance AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.38 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements

Program Description

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP is an existing AMP, formerly a portion of the PTN Containment Cable Inspection Program. This AMP provides reasonable assurance that the intended functions of cable and connection electrical insulation exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the CLB through the SPEO.

This AMP applies to accessible non-EQ electrical cable and connection electrical insulation material within the scope of SLR subjected to adverse (e.g., excessive heat, radiation, and/or moisture) localized environment(s). Adverse localized environments are identified through the use of an integrated approach which includes, but is not limited to, a review of relevant site-specific and industry OE, a review of EQ zone maps, real-time infrared thermographic inspections, conversations with plant personnel cognizant of specific area and room environmental conditions, etc. To facilitate the identification of an adverse localized environment, a temperature threshold of 107.3°F (41.8°C) and a radiation threshold of 3E+06 rads have been established for cable and connection insulation materials within the scope of this program.

Accessible non-EQ insulated cables and connections within the scope of SLR installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. The inspection of accessible cable and connection insulation material is used to evaluate the adequacy of inaccessible cable and connection electrical insulation. If visual inspections identify cable jacket and connection insulation surface anomalies, then testing may be performed. A sample population of cable and connection insulation is utilized if testing is performed. The component sampling methodology includes a representative sample of in-scope non-EQ electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selections is documented.

The first inspection for SLR is to be completed no earlier than 10 years prior to the SPEO and no later than six months prior to entering the SPEO. Recurring inspections are to be performed at least once every 10 years thereafter.

Site-specific OE will be evaluated to identify in-scope cable and connection insulation previously subjected to adverse localized environment during the initial PEO. Cable and connection insulation will be evaluated to confirm that the dispositioned corrective actions continue to support in-scope cable and connection intended functions during the SPEO.

If testing is deemed necessary, a sample of 20 percent of each cable and connection type with a maximum sample size of 25 is tested. Trending actions are not included as part of this AMP. Acceptance criteria under this AMP specifies that no unacceptable visual indications of cable and connection jacket surface anomalies should be observed. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. If testing is deemed necessary, the acceptance criteria for testing electrical cable and connection insulation material is defined in the WO for each cable and connection test and is determined by the specific type of test performed and the specific cable tested.

NUREG-2191 Consistency

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Exceptions to NUREG-2191

None.

Enhancements

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP will be enhanced for alignment with NUREG-2191, as discussed below. This enhanced AMP is to be implemented with inspections starting no earlier than 10 years prior to the SPEO and completed no later than six months prior to entering the SPEO, or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 10. Operating Experience	Update the governing AMP specification/procedure to do the following: • Expand scope to include cable and connection inspections outside Containment. • Identify adverse localized environments utilizing the guidance in NUREG-2191, Section XI.E1, and EPRI TR-109619 (Reference B.3.93), "Guideline for the Management of Adverse Localized Equipment Environments." Palo Alto, California: Electric Power Research Institute, June 1999. • Inspect for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, or moisture). • If cable testing is deemed necessary, utilize sampling methodology consistent with guidance of Section XI.E1 of NUREG-2191.

Element Affected	Enhancement
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 10. Operating Experience (continued)	• Ensure personnel involved with field implementation are qualified on cable aging inspection techniques. • Review site-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation during the original PEO. Evaluate to confirm that the dispositioned corrective actions continue to support in-scope cable and connection intended functions during the SPEO.

Operating Experience

Industry Operating Experience

Industry operating experience has shown that ALEs caused by elevated temperature, radiation, or moisture for insulated electrical cables and connections may exist. For example, insulated cables and connections routed next to or above (within 3 feet) steam generators, pressurizers, or hot process pipes, such as feedwater lines. These ALEs have been found to cause degradation of the insulating materials on electrical cables and connections that are visually observable, such as color changes or surface cracking. These visual indications, along with cable condition monitoring, can be used as indicators of degradation.

That industry operating experience resulted in the development and need for this program to ensure that insulated cables and connections, located inside and outside of containment, are not exposed to ALEs that subject the insulated cables and connections to environments that exceed their respective 80-year temperature and radiation limits.

Site-Specific Operating Experience

The following review of site-specific operating experience during the first PEO, including past corrective actions, provides objective evidence that the PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be effective in ensuring that intended functions of insulated cables and connections within the scope of the program are maintained during SPEO.

Per the PTN SLR Evaluation Report in January 2016, the presence of an adverse localized environment (temperature-related) was documented that adversely affected the insulation on nearby cables above the hot leg piping inside Unit 3 containment in 2004. Inaccessible instrumentation cable in this area had degraded to the point to cause a loss of signal on a pressure transmitter. Further investigation revealed numerous heat-degraded instrumentation cables above the hot leg piping in both units. The excess heat was attributed to gaps in the hot leg piping insulation, uninsulated pipe stubs from when the hot leg bypass resistance temperature detector (RTD) piping had been removed, the close proximity of the ceiling with no path to let the heat escape and the closure of the normal containment cooler damper (which would have provided cooling air to the area). The corrective actions identified during the 2004 discovery included repairing the gaps in the insulation, insulating the bypass RTD pipe stubs, and wiring open the dampers. All degraded cables were replaced with high temperature resilient insulated cables (silicone rubber). Temperature monitoring was installed to determine actual temperatures in the area during operation. In all cases, the average temperature was measured below the qualified life temperature of the replacement cables' insulation. The replacement cables will now perform their intended function throughout SPEO in their installed normal operating environment.

In January of 2013, during a troubleshooting effort on another unrelated action request issue in containment (inside the bio-wall), a degraded power lead was identified near an uninsulated hot process valve body. Other cables in flex conduits (near the same location) were also found to have degraded insulation requiring replacement under the CAP. The original exposed cable insulation had signs of severe overheating and was grounding on the inside of the conduit. The corrective actions included conducting a walkdown where ALEs are located (uninsulated hot process components and piping) for similar cases where cables may be subjected (within 6 inches) to very high temperatures from these hot components. No other cases were noted or discovered from the walkdown. The existing program conducts visual inspections on accessible EQ cables in scope of the EQ program in harsh environments. The enhanced program will expand the plant areas to include both harsh and mild environment areas where cables in scope of SLR exist (not just EQ cables). As industry operating experience has confirmed, there are many cases found where nearby (within 3 feet) cables exposed to the adverse effects of ALEs are not just limited to being in harsh environments and do not only adversely affect EQ cables. In addition, ALEs exist outside of containment and not always associated with uninsulated hot process piping and components.

PTN– NRC Post-Approval Site Inspection for License Renewal Inspection Report, July 12, 2012, Accession No. ML12195A272 (Reference B.3.60) identified the need for an enhanced program through periodic assessments of the program. Periodic assessments facilitate continuous improvement demonstrating that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program provides reasonable assurance that the intended functions of insulated cables and connections exposed to adverse localized environments can be maintained consistent with the CLB during the SPEO.

The existing program (not enhanced) is limited to areas inside containment, and involve inspections of only accessible EQ cables. The existing program discovered and verified that ALEs inside containment existed that have induced accelerated aging upon a population of cables leading to one instrumentation circuit failure. The one circuit failure was a result of creating a "new" ALE by not completing work activities in Containment (not restoring pipe and equipment insulation when the work activity is complete). Even though the program intention is to discover ALEs potentially adversely affecting nearby insulated cables and connections in their normal operating environment and plant configuration, this program also discovers cases where plant conditions may change from work activity actions or plant modifications. The lessons learned from site-specific operating experience is to ensure craft activities include the total restoration of component insulations and ventilation damper alignments at the conclusion of each work activity. Containment closeout procedures were enhanced to address piping insulation (restoration) and damper deficiencies.

The enhanced program will also search for and discover any ALEs, with nearby insulated cables and connections, in accessible areas inside and outside containment where non-EQ insulated cables and connections in scope of license renewal exist.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program AMP will be capable of both detecting and trending the aging effects of adverse environments on insulated electrical cables and connections.

Enhancements to the AMP have been identified and implemented as a result of OE. Examples of the AMP being enhanced by OE are industry OE events demonstrating that there are numerous cases where cables are located/routed too close to major heat-emitting plant components that are not just limited to the containment area, and do not only affect EQ cables and connections. Site-specific OE has reflected unique configurations in not-easily-accessible areas of containment that have incurred cable insulation damage from both human error (non-completion of work activities, insulation restoration, and damper louver position restoration) and close cable routing to uninsulated portions of hot process components. Prompt corrective actions were taken to prevent recurrence and evaluate if other similar configuration cases exist in other plant areas. By expanding the plant areas to be inspected in the enhanced program, and the inclusion of non-EQ insulated cables and connections, there is increased confidence that the OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.39 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits

Program Description

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP is a new AMP for SLR. This AMP will manage the aging effects of the applicable cables in the following systems or sub-systems.

- Nuclear Instrumentation: excore source, intermediate, and power range
- Process Radiation Monitoring:
  - Containment air particulate monitors
  - Containment gas monitors
  - Control room HVAC emergency monitor (common)
  - Control room normal air intake monitor (common)

In most areas within a nuclear power plant the actual operating environment (e.g., temperature, radiation, or moisture) is less severe than the plant design bases environment. However, in a limited number of localized areas, the actual environment may be more severe than the plant design bases environment. These localized areas are characterized as “adverse localized environments” that represent a limited plant area where the operating environment is significantly more severe than the plant design basis environment. An adverse localized environment is based on the most limiting environment (e.g., temperature, radiation, or moisture) for the cable or connection insulation.

Exposure of electrical insulation to adverse localized environments caused by temperature, radiation, or moisture can cause age degradation resulting in reduced electrical insulation resistance, moisture intrusion-related connection failures, or errors induced by thermal transients. Reduced electrical insulation resistance causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in electrical insulation resistance is a concern for all circuits, but especially those with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation circuits, because a reduced insulation resistance may contribute to signal inaccuracies.

In this AMP, in addition to the evaluation and identification of adverse localized environments, either of two methods can be used to identify the existence of electrical insulation aging effects for cables and connections. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation aging degradation. In the second method, direct testing of the cable system is performed.

Results from the calibrations or surveillances of components within the scope of SLR will be reviewed. The parameters monitored will be determined from the specific calibration, surveillances or testing performed and will be based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant procedures. Cable testing will be performed on cables in the scope of the program that are disconnected during instrument calibration using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests, or time domain reflectometry tests). The parameters for cable testing will be specified in plant procedures.

Reviewing the data obtained during normal calibrations or surveillances will allow the detection of severe aging degradation prior to the loss of the cable and connection intended function. The first reviews of calibration or surveillance results for SLR will be completed no later than six months prior to entering the SPEO with ensuing reviews occurring every 10 years thereafter. Calibrations or surveillances that fail to meet acceptance criteria will be reviewed at the time of the calibration or surveillance. Cable testing is performed by plant procedures on cables within the scope of SLR that are disconnected during instrument calibration. Cable system testing will be performed on the sensitive instrumentation cables that are disconnected during instrument loop calibrations. When the detectors are disconnected during calibrations, these circuits will be tested to determine insulation resistance reduction using tests such as time domain reflectometry or other insulation resistance tests. The first test, using a proven method for detecting deterioration for the insulation system, will be completed no later than six months prior to entering the SPEO with ensuing tests occurring at least every 10 years.

In accordance with the PTN CAP, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the CLB through the SPEO. Trending actions are not included as part of this AMP.

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP scope will be added to existing PTN procedures for governing its surveillance. The existing pertinent procedures will be updated to perform the following:

- A review of calibration results and/or findings of surveillance programs to detect aging degradation.
- Testing on the sensitive instrumentation cables that are disconnected during instrument loop calibrations to determine cable system insulation physical, mechanical, and chemical properties, as applicable.

This AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E2, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Site-Specific Operating Experience</u>

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP is a new program for PTN to be implemented prior to the SPEO. Therefore, there is no existing site-specific OE to validate the effectiveness of this program at PTN; however, there is OE relevant to components within the scope of the PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP.

As this is a new AMP, the PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP was not included in the scope of the July 2012 NRC post-approval site inspection (Inspection reports 05000250/2012008 and 05000251/2012008, Reference B.3.60) prior to entering the original PEO; however, the post-approval site inspection did include review of the Containment Cable Inspection Program. The Containment Cable Inspection Program included a CHAR™ (Automatic Characterization System, CHAR Services, Inc.) test of the power range and intermediate range cables to identify any cable degradation. The testing performed is similar to that required by the PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP proposed for subsequent license renewal. There were no observations or deficiencies noted for the Containment Cable Inspection Program as part of the post-approval site inspection.

During the performance of the CHAR test in April of 2016, the center conductor to inner shield resistance for Power Range Channel IV detector N-4-44 at PTN Unit 4 was found to be lower than procedurally required. This issue was documented in the CAP, and a trouble shooting plan was established for testing the cable to ensure the cable did not require replacement. The CHAR test was performed again prior to the end of the outage with satisfactory results, and no repairs or further troubleshooting was necessary. The results were documented in the CAP. A moisture issue that may have dissipated over time was suspected to have caused the initial low resistance readings.

During the spring 2016 refueling outage, the NI source range detectors at PTN Unit 4 were declared inoperable multiple times due to intermittent signal fluctuations. The signal fluctuations of the NI Source Range detectors had been identified during previous Unit 3 and Unit 4 outages. As described in the corrective action system, the cause for source range fluctuations has been attributed to cable degradation due to aging, thermal wear, radiation exposure, water and moisture damage as was previously identified in the CAP. Per the CAP, both the Unit 3 and Unit 4 cables are being considered for replacement in future outages. In the interim, the source range detectors have been restored to operable status to support plant operations.

These examples provide objective evidence that when cable degradation due to adverse localized environments caused by temperature, radiation, or moisture adversely impact the insulation resistance of cables and connections in neutron monitoring applications PTN has taken the appropriate measures to manage loss of intended function. The excore NIS cables within the scope of this new AMP will be tested to determine a reduction in insulation resistance using tests such as time domain reflectometry or other insulation resistance tests. The first test, using a proven method for detecting deterioration for the insulation system, will be completed before the subsequent PEO with ensuing tests occurring at least every 10 years thereafter. This new AMP will be informed and enhanced as additional site-specific OE is accumulated to ensure a reduction in electrical insulation resistance in circuits with sensitive, high-voltage, low-level current signals, is detected prior to a component loss of intended function.

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP will be informed and enhanced when necessary through the systematic and ongoing review of both site-specific and industry OE to ensure program effectiveness consistent with the discussion in Appendix B of the NUREG-2191. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits AMP is a new program that will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.40 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements

Program Description

The PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP for SLR. The purpose of the PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible medium-voltage power cables (operating voltages of 2 kV to 35 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ medium-voltage cables within the scope of SLR exposed to wetting or submergence (i.e., significant moisture). Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that occurs for a limited time, as in the case of automatic or passive drainage, is not considered significant moisture for this AMP.

Periodic actions to mitigate inaccessible medium-voltage cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduits and removing water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed no later than six months prior to entering the SPEO. Inspection frequencies are adjusted based on inspection results including site-specific OE but with a minimum inspection frequency of at least once annually. Inspections are also performed after event driven occurrences, such as heavy rain or flooding.

Site-specific parameters are established for the initiation of an event driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture. If water is found inside a manhole during an inspection, dewatering activities are initiated, the source of the water intrusion is determined, and a visual inspection of the cable jacket for degradation is documented and assessed.

Underground non-EQ medium-voltage power cables within the scope of SLR exposed to significant moisture are tested to determine the age degradation of the electrical insulation. Cable testing occurs at least once every 6 years. The first tests for SLR are to be completed no later than six months prior to entering the SPEO, with subsequent tests performed at least once every 6 years thereafter. Submarine or other cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test with additional periodic tests and inspections determined by the one-time test/inspection results as well as industry and site-specific OE. Cable testing depends on the cable type, application, and construction, and typically employs a combination of test techniques capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. A PTN specific inaccessible medium-voltage cable test matrix will be developed to document inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables based on OE.

An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The acceptance criteria for cable testing is defined for each cable test and is determined by the specific type of test performed and the specific cable tested. Acceptance criteria for inspections for water accumulation are defined by the direct indication that cable support structures are intact and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected and their operation verified to prevent unacceptable exposure to significant moisture. Acceptance criterion for visual inspection of cable jackets is no unacceptable signs of surface abnormalities that indicate unusual cable insulation aging degradation may exist.

The aging management of the physical structures, including cable support structures of cable vaults/manholes, is managed by the PTN Structures Monitoring AMP.

The PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP scope will be added to existing PTN procedures for governing its surveillance. The existing pertinent procedures will be updated to perform the following:

- Perform testing of medium-voltage power cables within the scope of SLR exposed to wetting or submergence to detect aging degradation;

- Inspect for water accumulation in cable manholes and conduits and remove water as needed;

- Visually inspect cable jacket for degradation if water is found inside a manhole during an inspection;

- Periodically inspect dewatering systems (e.g., sump pumps and passive drains) and verify their operation and associated alarms;

- Inspect cable manholes and conduits for water accumulation after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding;

- Perform a one-time inspection and test of inaccessible medium-voltage cables designed for continuous wetting or submergence (e.g., submarine cables)

This AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E3A, “Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualifications Requirements.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

As described below, industry operating experience indicates that cables exposed to significant moisture can lead to degradation of insulation causing a loss of intended function to susceptible systems and components in nuclear power plants. The PTN program is based on the program description in NUREG-2191 (Reference B.3.9), which in turn is based on industry OE.

By way of background, NRC Bulletin 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed safety-related equipment. The bulletin detailed accounts of leaking ductbanks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC Generic Letter 2007-01, issued February 7, 2007 further cited NRC Bulletin 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. PTN submitted a formal response to NRC Generic Letter 2007-01, under L-2007-067 (Reference B.3.141). Under that documented response, it detailed two cable related issues as follows:

1. In 1994, the 480-volt feeder cable for a traveling screen motor was intermittently tripping the breaker. The cable was found to be damaged. The apparent cause of the cable damage was due to physical interface with a deteriorated conduit section.

2. In 1994, the C phase 4160-volt feeder cable for the steam generator feedwater pump (SGFWP) motor was identified with a low, but acceptable megger reading. The cable was replaced during the next refueling outage to prevent future failure. The underground

portion of the cable was not removed for inspection and testing. The cause of the cables low megger reading was not determined.

In addition, the PTN response detailed an existing manhole inspection program. The manhole inspection program was established in 2001 and ensures manhole sump pumps and drains are functioning properly, therefore minimizing the amount of time cable is exposed to a wet environment.

A manhole inspection procedure has since been created to provide the instructions, steps, and actions necessary to ensure proper manhole inspection. The preventative maintenance activities (PMs) in the procedure, groups the manholes on the basis of past trends of water found, mechanisms for removing water when identified, and whether they are part of hurricane preparedness. The PMs address all of PTN's manholes and establish inspection frequencies ranging from 3 to 36 months.

Site-Specific Operating Experience

The PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new program for PTN to be implemented prior to the SPEO. Therefore, there is no existing program-specific OE to validate the effectiveness of this program at PTN; however, there is some OE relevant to components within the scope of the PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

Note that all inaccessible medium voltage cables within the scope of this new AMP are lead sheathed and designed for submergence. Aside from a single event associated with the 4A Steam Generator Feed Pump (SGFP) motor detailed below, site specific operating experience has proven this cable design to be highly reliable in underground, wetted environments.

1. During testing and grounding of the 4A SGFP motor in March of 2008, low megger readings were obtained. The affected cables were lead sheathed cables designed for submergence. Of the nine SGFP motor feeder cables, two (B1 and C1) exhibited signs of low insulation resistance. Portions of each cable were sampled and sent to a lab for testing. The test results were dispositioned as follows:

    a. The B1 cable exhibited aging, but no degradation that would have prevented the continued use of the cable. The lab test results credited the taped cable terminations or cable degradation of the inaccessible portions that were not sent to the lab as a cause for the low megger readings.

    b. The C1 cable was significantly damaged by water intrusion due to a hole in the jacket about 14 feet from the location of the motor. After assessing multiple root causes for the hole in the cable jacket, the evaluation determined the likely cause was a protrusion from a conduit at or near a 90-degree elbow located approximately 3 feet underground below the motor junction box.

Although the B1 results indicated two potential causes, results of testing for the C1 cable theorized that the cable integrity was compromised due to water intrusion from the hole in the jacket. All nine SGFP motor feeder cables were replaced.

2. While performing inspection of MH 427 in June of 2013, water was discovered inside, about 1/2 inch above sump level. The sump pump did not appear to be working properly. Upon further investigation, there was less than 1/2 inch of water in the MH and no cables were submerged. This condition was entered into the CAP to check the sump pumps float switch or replace the sump pump. The sump pump was replaced. This manhole is inspected on an annual basis in accordance with the PTN manhole inspection procedure. Review of the cable program health report indicates no subsequent flooding issues for MH 427.

These above examples of site-specific OE demonstrate that when water inside a manhole has been identified at PTN, appropriate corrective measures are taken in a timely fashion in order to keep the cables free from significant moisture. The manholes within the scope of this new AMP are to be visually inspected periodically based on water accumulation over time. Inspection frequencies are adjusted based on inspection results including site-specific OE but with a minimum inspection frequency of at least once annually. Site-specific OE, similar to this, will be used in the adjustment of the inspection frequency of this new AMP. Since there has only been one failure of lead sheathed cables at PTN, there is high confidence in the reliably of lead sheathed cables during the SPEO. This new AMP will be informed and enhanced as additional site-specific OE is accumulated to ensure cables are kept free from significant moisture.

System Health Reports

A review of quarterly cable program health reports issued from Q1 2012 to Q4 2017 was conducted to ascertain existing cable program performance during the PEO. As explained below, system health status fluctuated between YELLOW and WHITE (only GREEN is considered acceptable) until Q4 2016, where it improved to GREEN and has remained GREEN since. Examples of actions taken during the period from Q1 2012 to Q4 2017 included the installation of water level monitoring equipment, automatic sump pumps and inspections of manholes.

Looking back, a deficiency was identified in the Q4-2014 Health Report stemming from the lack of documented bridging strategies associated with low voltage (480V) cables and monitoring of manholes where remote monitoring equipment had reliability issues. In response, necessary 480V cables were identified and incorporated into the plant cable condition monitoring program for periodic trended testing and monitoring. The identified gaps were resolved via the CAP, and documented as closed in the Q4-2016 Health Report. The identified issue was resolved via the aforementioned actions with no additional actions required by PTN.

The number of manholes with water accumulation has decreased. Enhancements such as the installation of water level monitoring equipment and automatic sump pumps have been implemented as a result of site-specific OE. There is increased awareness by station personnel to identify cables exposed to significant moisture, and there are on-going improvements to the program through improved metrics detailed in the health reports. Therefore, there is sufficient confidence that implementation of the PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will effectively identify and address degradation prior to component loss of intended function.

Enhancements to the AMP have been identified and implemented as a result of OE. An example of the AMP being enhanced by OE is the installation of water level monitoring equipment and restoration of sump pumps as a result of site-specific OE. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.41 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements

Program Description

The PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP for SLR. The purpose of the PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is to provide reasonable assurance that the intended functions of underground non-EQ instrument and control (I&C) cables that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ I&C cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This AMP is a condition monitoring program. However, periodic actions are taken to prevent inaccessible or underground I&C 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. The inspection frequency for water accumulation is established and performed based on site-specific OE with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed no later than six months prior to entering the SPEO. Inspections for water accumulation are also performed after event driven occurrences, such as heavy rain or flooding. Site-specific parameters are established for the initiation of an event driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture.

If water is found inside a manhole during an inspection, dewatering activities are initiated, the source of the water intrusion is determined, and a visual inspection of the cable jacket for degradation is documented and assessed.

Underground non-EQ instrumentation and control cables within the scope of SLR are periodically visually inspected to assess age degradation of the electrical insulation. Inaccessible and underground instrumentation and control cables found to be exposed to significant moisture are evaluated (e.g., a determination is made as to whether a periodic or one-time test is needed for condition monitoring of the cable insulation system). Cable installation systems that are known via inspection or subsequently found through either industry or site-specific OE to degrade with continuous exposure to significant moisture (e.g., Vulkene and Raychem cross-linked polyethylene) are also tested to monitor cable electrical insulation degradation over time. The specific type of test(s) will be proven technique(s) capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. One or more tests may be required due to cable application, construction, and electrical insulation material to determine the age degradation of the cable.

Visual inspection of inaccessible and underground I&C cables also includes a determination as to whether other adverse environments exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system.

For inaccessible instrumentation and control cables exposed to significant moisture, visual inspection frequency is adjusted based on inspection and test results as well as site-specific and industry OE. For inaccessible and underground instrumentation and control cables exposed to significant moisture where testing is required, a one-time test is performed. Visual inspection occurs at least once every 6 years and may be coordinated with the periodic inspection for water accumulation. The initial visual inspection for SLR and testing (if recommended) will be completed no later than six months prior to entering the SPEO.

Cables are periodically visually inspected for cable jacket surface abnormalities, such as: embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the instrumentation and control cable electrical insulation.

The specific type of test(s) determines, with reasonable assurance, in-scope inaccessible instrumentation, and control cable insulation age degradation. One or more tests may be required based on cable application, and electrical insulation material to determine the age degradation of the cable insulation. Testing of installed inservice inaccessible instrumentation and control cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible instrumentation and control cables when testing is required in this AMP.

The cable testing portion of the AMP utilizes sampling. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other inaccessible instrumentation and control cables not tested and whether the tested sample population should be expanded. The PTN CAP evaluates test or visual inspection results that do not meet acceptance criteria and determine appropriate corrective action (e.g., additional visual inspections or testing).

An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of the intended function. The acceptance criteria for each cable test is determined by the specific type of test performed and the specific cable tested. Acceptance criteria for water accumulation inspections are defined by the direct indication that cable support structures are intact and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected and their operation verified. Acceptance criterion for visual inspection shall show that I&C cable jacket materials are free from unacceptable surface abnormalities that indicate excessive cable insulation aging degradation.

Aging management of physical structures, including cable support structures and cable vaults or manholes, are managed by the PTN Structures Monitoring AMP (Section B.2.3.35) rather than this AMP.

The PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP scope will be added to existing PTN procedures for governing its surveillance. The existing pertinent procedures will be updated to perform the following:

- Identify the instrumentation and control cables and manholes within the scope of this program;
- If required, perform testing of instrumentation and control cables within the scope of SLR exposed to wetting or submergence to detect aging degradation;
- Inspect for water accumulation in cable manholes and conduits and remove water as needed;
- Visually inspect cable jacket for degradation if water is found inside cable manhole or conduit during inspection for water accumulation;
- Periodically inspect dewatering systems (e.g., sump pumps and passive drains) and verify their operation and associated alarms;
- Inspect cable manholes and conduits for water accumulation after event driven occurrences, such as heavy rain or flooding;
- Perform a one-time inspection and test of inaccessible instrumentation and control cables designed for continuous wetting or submergence

This AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E3B, “Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

As described below, industry operating experience indicates that cables exposed to significant moisture can lead to degradation of insulation causing a loss of intended function to susceptible systems and components in nuclear power plants. The PTN program is based on the program description in NUREG-2191 (Reference B.3.9), which in turn is based on industry OE.

By way of background, NRC Bulletin 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed safety-related equipment. The bulletin detailed accounts of leaking ductbanks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC Generic Letter 2007-01, issued February 7, 2007 further cited NRC Bulletin 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. PTN submitted a formal response to NRC Generic Letter 2007-01, under L-2007-067 (Reference B.3.141). Under that documented response, it detailed two cable related issues as follows:

1. In 1994, the 480-volt feeder cable for a traveling screen motor was intermittently tripping the breaker. The cable was found to be damaged. The apparent cause of the cable damage was due to physical interface with a deteriorated conduit section.

2. In 1994, the C phase 4160-volt feeder cable for the steam generator feedwater pump (SGFWP) motor was identified with a low, but acceptable megger reading. The cable was replaced during the next refueling outage to prevent future failure. The underground

portion of the cable was not removed for inspection and testing. The cause of the cables low megger reading was not determined.

In addition, the PTN response detailed an existing manhole inspection program. The manhole inspection program was established in 2001 and ensures manhole sump pumps and drains are functioning properly, therefore minimizing the amount of time cable is exposed to a wet environment.

A manhole inspection procedure has since been created to provide the instructions, steps, and actions necessary to ensure proper manhole inspection. The preventive maintenance activities (PMs) in the procedure, groups the manholes on the basis of past trends of water found, mechanisms for removing water when identified, and whether they are part of hurricane preparedness. The PMs address all of PTN's manholes and establish inspection frequencies ranging from 3 to 36 months.

Site-Specific Operating Experience

The following review of site-specific operating experience during the first PEO, including past corrective actions, provides reasonable assurance that the Cable aging management program effectively manages insulation aging effects so that intended functions will be maintained during the SPEO. This new program will be implemented at PTN prior to the SPEO, so there is no existing program-specific OE. However, the following OE example below is relevant to components within the scope of the AMP:

1. While performing inspection of MH 427 in June 6, 2013, water was discovered inside, about 1/2" above sump level. The sump pump did not appear to be working properly. Upon further investigation, there was less than 1/2 inch of water in the MH and no cables were submerged. This condition was entered into the CAP to check the sump pumps float switch or replace the sump pump. The sump pump was replaced. This manhole is inspected on an annual basis in accordance with the PTN manhole inspection procedure. Review of the cable program health report indicates no subsequent flooding issues for MH 427.

The above example of site-specific OE demonstrates that when water inside a manhole has been identified at PTN, appropriate corrective measures are taken in a timely fashion in order to keep the cables free from significant moisture. The manholes within the scope of this new AMP are to be visually inspected periodically based on water accumulation over time. Inspection frequencies are adjusted based on inspection results including site-specific OE but with a minimum inspection frequency of at least once annually. Site-specific OE, similar to this, will be used in the adjustment of the inspection frequency of this new AMP. This new AMP will be informed and enhanced as additional site-specific OE is accumulated to ensure cables are kept free from significant moisture.

<u>System Health Reports</u>

A review of quarterly cable program health reports issued from Q1-2012 to Q4 2017 was conducted to ascertain existing cable program performance during the PEO. As explained below, system health status fluctuated between YELLOW and WHITE (only GREEN is considered acceptable) until Q4-2016, where it improved to GREEN and has remained GREEN since. Examples of actions taken during the period from Q1-2012 to Q4 2017 included the installation of water level monitoring equipment, restoration of sump pumps and inspections of manholes.

Looking back, a deficiency was identified in the Q4-2014 Health Report stemming from the lack of documented bridging strategies associated with low voltage (480V) cables and monitoring of manholes where remote monitoring equipment had reliability issues. In response, necessary 480V cables were identified and incorporated into plant cable condition monitoring program for periodic trended testing and monitoring. The identified gaps were resolved via the CAP, and documented as closed in the Q4-2016 Health Report. The identified issue was resolved via the aforementioned actions with no additional actions required by PTN.

The number of manholes with water accumulation has decreased. There is increased awareness by station personnel to identify cables exposed to significant moisture, and there are on-going improvements to the program through improved metrics detailed in the health reports. Therefore, there is sufficient confidence that implementation of the PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will effectively identify and address degradation prior to component loss of intended function.

Enhancements to the AMP have been identified and implemented as a result of OE. An example of the AMP being enhanced by OE is the installation of water level monitoring equipment and restoration of sump pumps as a result of site-specific OE. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.42 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements

Program Description

The PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP for SLR. The purpose of the PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible or underground low-voltage ac and dc power cables (i.e., typical operating voltage of less than 1,000 V, but no greater than 2 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ low-voltage cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible or underground 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. The inspection frequency for water accumulation is established and performed based on site-specific OE with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed no later than six months prior to entering the SPEO. Additional tests and periodic visual inspections are determined by the test/inspection results and industry and site-specific aging degradation OE with the applicable cable electrical insulation. The aging management of the physical structures, including cable support structures of cable vaults/manholes, is managed by the PTN Structures Monitoring AMP (Section B.2.3.35).

Inspections for water accumulation are also performed after event driven occurrences, such as heavy rain or flooding. -specific parameters are established for the initiation of an event driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture.

Underground non-EQ low-voltage power cables within the scope of SLR are periodically visually inspected to assess age degradation of the electrical insulation. Inaccessible and underground low-voltage power instrumentation and control cables found to be exposed to significant moisture are evaluated (e.g., a determination is made as to whether a periodic or one-time test is needed for condition monitoring of the cable insulation system). Cable installation systems that are known or subsequently found through either industry or site-specific OE to degrade with continuous exposure to significant moisture (e.g., Vulkene and Raychem cross-linked polyethylene) are also tested to monitor cable electrical insulation degradation over time. The specific type of test(s) will be proven technique(s) capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. One or more tests may be required due to cable application, construction, and electrical insulation material to determine the age degradation of the cable. Visual inspection occurs at least once every 6 years with the initial inspection occurring no later than six months prior to entering the SPEO.

Cables are periodically visually inspected for cable jacket surface abnormalities such as: embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the low-voltage power cable electrical insulation. Age degradation of the cable jacket may indicate accelerated age degradation of the electrical insulation due to significant moisture or other aging mechanisms. Visual inspection of inaccessible and underground low-voltage power cables also includes a determination as to whether other adverse environments may exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system.

The cable testing portion of the AMP utilizes sampling. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other inaccessible low-voltage power cables not tested and whether the tested sample population should be expanded. The specific type of test(s) determine, with reasonable assurance, in-scope inaccessible low-voltage power cable insulation age degradation. One or more tests may be required based on cable application, and electrical insulation material to determine the age degradation of the cable insulation. Testing of installed inservice low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium voltage power cables or instrumentation and control cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is required in this AMP.

An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. Acceptance criteria for inspections for water accumulation are defined by the direct indication that cable support structures are intact and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected and their operation verified to prevent unacceptable exposure to significant moisture. Acceptance criterion for visual inspection of cable jackets is no unacceptable signs of surface abnormalities that indicate excessive cable insulation aging degradation may exist. The acceptance criteria for cable testing (if recommended) is defined in the WO for each cable test and is determined by the specific type of test performed and the specific cable tested.

If recommended, initial cable testing is performed once by utilizing sampling to determine the condition of the electrical insulation. Test results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation.

The PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP scope will be added to existing PTN procedures for governing its surveillance. The existing pertinent procedures will be updated to perform the following:

- Inspect for water accumulation in cable manholes and conduits and remove water as needed;
- Visually inspect cable jacket for degradation if water is found inside cable manhole or conduit during inspection for water accumulation;
- Perform testing of low-voltage power cables within the scope of SLR exposed to wetting or submergence to detect aging degradation;
- Periodically inspect dewatering systems (e.g., sump pumps and passive drains) and verify their operation and associated alarms;
- Inspect cable manholes/vaults and conduits for water accumulation after event driven occurrences, such as heavy rain or flooding;
- Perform a one-time inspection and test of inaccessible low-voltage cables designed for continuous wetting or submergence

This AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section

XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

As described below, industry operating experience indicates that cables exposed to significant moisture can lead to degradation of insulation causing a loss of intended function to susceptible systems and components in nuclear power plants. The PTN program is based on the program description in NUREG-2191 (Reference B.3.9), which in turn is based on industry OE.

By way of background, NRC Bulletin 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed safety-related equipment. The bulletin detailed accounts of leaking ductbanks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC Generic Letter 2007-01, issued February 7, 2007 further cited NRC Bulletin 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. PTN submitted a formal response to NRC Generic Letter 2007-01, under L-2007-067 (Reference B.3.141). Under that documented response, it detailed two cable related issues as follows:

1. In 1994, the 480-volt feeder cable for a traveling screen motor was intermittently tripping the breaker. The cable was found to be damaged. The apparent cause of the cable damage was due to physical interface with a deteriorated conduit section.

2. In 1994, the C phase 4160-volt feeder cable for the steam generator feedwater pump (SGFWP) motor was identified with a low, but acceptable megger reading. The cable was replaced during the next refueling outage to prevent future failure. The underground portion of the cable was not removed for inspection and testing. The cause of the cables low megger reading was not determined.

In addition, the PTN response detailed an existing manhole inspection program. The manhole inspection program was established in 2001 and ensures manhole sump pumps and drains are functioning properly, therefore minimizing the amount of time cable is exposed to a wet environment.

A manhole inspection procedure has since been created to provide the instructions, steps, and actions necessary to ensure proper manhole inspection. The preventative maintenance activities (PMs) in the procedure, groups the manholes on the basis of past trends of water found, mechanisms for removing water when identified, and whether they are part of hurricane preparedness. The PMs address all of PTN's manholes and establish inspection frequencies ranging from 3 to 36 months.

Site-Specific Operating Experience

The following review of site-specific operating experience during the first PEO, including past corrective actions, provides reasonable assurance that the cable aging management program effectively manages insulation aging effects so that intended functions will be maintained during the SPEO.

The PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new program for PTN to be implemented prior to the SPEO. Therefore, there is no existing program-specific OE to validate the effectiveness of this program at PTN; however, there is OE relevant to components within the scope of the PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

While performing inspection of MH 427 June 6 of 2013, water was discovered inside, about 1/2 inch above sump level. The sump pump did not appear to be working properly. Upon further investigation, there was less than 1/2 inch of water in the MH and no cables were submerged. This condition was entered into the CAP to check the sump pumps float switch or replace the sump pump. The sump pump was replaced. This manhole is inspected on an annual basis in accordance with the PTN manhole inspection procedure. Review of the cable program health report indicates no subsequent flooding issues for MH 427.

The above example of site-specific OE demonstrates that when water inside a manhole has been identified at PTN, appropriate corrective measures are taken in a timely fashion in order to keep the cables free from significant moisture. The manholes within the scope of this new AMP are to be visually inspected periodically based on water accumulation over time. Inspection frequencies are adjusted based on inspection results including site-specific OE but with a minimum inspection frequency of at least once annually. Site-specific OE, similar to this, will be used in the adjustment of the inspection frequency of this new AMP. This new AMP will be informed and enhanced as additional site-specific OE is accumulated to ensure cables are kept free from significant moisture.

System Health Reports

A review of quarterly cable program health reports issued from Q1-2012 to Q4 2017 was conducted to ascertain existing cable program performance during the PEO. As explained below, system health status fluctuated between YELLOW and WHITE (only GREEN is considered acceptable) until Q4-2016, where it improved to GREEN and has remained GREEN since.

Examples of actions taken during the period from Q1-2012 to Q4 2017 included the installation of water level monitoring equipment, automatic sump pumps and inspections of manholes.

Looking back, a deficiency was identified in the Q4-2014 Health Report stemming from the lack of documented bridging strategies associated with low voltage (480V) cables and monitoring of manholes where remote monitoring equipment had reliability issues. In response, necessary 480V cables were identified and incorporated into the plant cable condition monitoring program for periodic trended testing and monitoring. The identified gaps were resolved via the CAP, and documented as closed in the Q4-2016 Health Report. The identified issue was resolved via the aforementioned actions with no additional actions required by PTN.

The number of manholes with water accumulation has decreased. Enhancements such as the installation of water level monitoring equipment and automatic sump pumps have been implemented as a result of site-specific OE. There is increased awareness by station personnel to identify cables exposed to significant moisture, and there are on-going improvements to the program through improved metrics detailed in the health reports. Therefore, there is sufficient confidence that implementation of the PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will effectively identify and address degradation prior to component loss of intended function.

Enhancements to the AMP have been identified and implemented as a result of OE. An example of the AMP being enhanced by OE is the installation of water level monitoring equipment and restoration of sump pumps as a result of site-specific OE. OE is reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements

Program Description

The PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP for SLR. The purpose of the PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP is to provide reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the EQ requirements of 10 CFR 50.49 and susceptible to age-related degradation resulting in increased resistance are maintained consistent with the CLB through the SPEO. This AMP manages increased resistance of connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation of the metallic portions of electrical cable connections within the scope of SLR.

Cable connections are used to connect cable conductors to other cable conductors or electrical devices. Connections associated with non-EQ cables within the scope of SLR are included in this AMP. Examples of connections used in nuclear power plants include bolted connectors, coaxial/triaxial connections, compression/crimped connectors, splices (butt or bolted), stress cones, and terminal blocks. Most connections involve insulating material and metallic parts. This AMP applies to the metallic parts of the non-EQ electrical cable connections within the scope of SLR and field cable connections associated with in-scope cables that are external connections terminating at active or passive devices. This condition monitoring AMP uses one-time testing to confirm the absence of age-related degradation of cable connections resulting in increased resistance of the connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation.

This AMP does not apply to the high voltage (> 35 kV) switchyard connections, wiring connections internal to an active assembly, and cable connections covered under the PTN EQ Program.

A representative sample of each type of non-EQ electrical cable connections within the scope of SLR are tested on a one-time test basis to confirm the absence of age-related degradation of the cable connection. The following factors will be considered for sampling: voltage level (medium and low-voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selection will be documented. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. One-time testing provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. Twenty percent of the population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting the components under test will be documented. The first tests for SLR are to be completed at least six months prior to entering the SPEO. Initial one-time test findings will document unacceptable conditions or degradation identified and whether they were determined to be age-related thereby requiring subsequent testing on a 10-year basis. This evaluation will include the justification and technical basis for not performing subsequent periodic testing if applicable.

As an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO and at least every 5 years thereafter. The basis for performing only the alternative periodic visual inspection to monitor age-related degradation of cable connections will be documented.

The acceptance criteria for each inspection or test will be defined by the type of inspection or test performed for the specific type of cable connection. Cable connections should not indicate abnormal temperatures for the application when thermography is used. Alternatively, connections should exhibit a low resistance value appropriate for the application when resistance measurement is used. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function. Trending actions are not included as part of this AMP; however, results are evaluated against acceptance criteria to confirm that increased connection resistance due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation is not an aging effect that requires a periodic AMP.

The PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

Industry operating experience (OE) was searched for applicability to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP. No specific OE was found that was directly applicable to the new AMP. In accordance with XI.E6 element 10 to NUREG-2191, PTN's site-specific operating experience is utilized to demonstrate the effectiveness of the PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

Site-Specific Operating Experience

The PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new program for PTN to be implemented prior to the SPEO. Therefore, there is no existing site-specific OE to validate the effectiveness of this program at PTN; however, there is OE relevant to components within the scope of the PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

As this is a new AMP, the PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP was not included in the scope of the July 2012 NRC post-approval site inspection (Inspection reports 05000250/2012008 and 05000251/2012008, Reference B.3.60) prior to entering the original PEO; however, the post-approval site inspection did include review of the Containment Cable Inspection Program.

1. The Containment Cable Inspection Program included an age related stiffness of nuclear instrumentation system (NIS) internal component cabinet wiring in 2003 for detector N-4-43 which resulted in breaking strands at the connection. The issue was determined to be caused by a vendor supplied internal component wiring deficiency. The connection was repaired and no remaining actions were required. While wiring connections internal to an active assembly are not within the scope of this AMP, this OE example represents a similar instance in which issues occurred at a cable connection.

2. During October of 2014, a thermocouple was observed to be failing intermittently on 4A Qualified Safety Parameter Display System (QSPDS). The issue was entered into the CAP. Screening notes stated core exit thermocouple (CET) indication was lost (either completely or intermittently) due to cable connection issues. The CAP resolution was to disconnect and clean cables during the outage, which has been successful in restoring CET indications.

Although the examples above were not definitively determined to be age related, they provide reasonable assurance that cable connection issues are addressed through PTN's CAP and existing maintenance practices. Consistent with information provided in NUREG-2191 with regards to industry OE, there have been limited numbers of age-related failures of cable connections reported at PTN, and existing maintenance practices have proven to be effective. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.44 High-Voltage Insulators

Program Description

The PTN High-Voltage Insulators AMP is a new AMP for SLR. The purpose of the PTN High-Voltage Insulators AMP is to provide reasonable assurance that the intended functions of high-voltage insulators within the scope of the program are maintained consistent with the CLB through the SPEO. This AMP was developed specifically to adequately manage high-voltage insulators susceptible to aging degradation due to local environmental conditions.

The scope of this AMP is limited to those high-voltage insulators in the power path utilized for restoration of off-site power following a Station Blackout event. This is a condition monitoring program. Periodic visual inspections along with periodic insulator coating and cleaning will be performed to manage high-voltage insulator aging effects throughout the SPEO.

Visual inspection provides reasonable assurance that the applicable aging effects are identified and high-voltage insulator age degradation is managed. Insulation materials used in high-voltage insulators may degrade when installed in a harmful environment. The insulation and metallic elements of high-voltage insulators are made of porcelain, cement, malleable iron, aluminum, and galvanized steel. Loss of metallic material can occur due to mechanical wear caused by oscillating movement of insulators due to wind. Surface corrosion in metallic parts may appear due to contamination or where galvanized or other protective coatings are worn. Additionally, airborne contamination, such as salt, can cause surface corrosion in metallic parts and various airborne contaminates such as dust, salt, fog, or industrial effluent can contaminate the insulator surface leading to reduced insulation resistance. Excessive surface contaminants or loss of material can lead to insulator flashover and failure.

The high voltage insulators within the scope of this AMP are visually inspected to detect reduced insulation resistance aging effects including cracks, foreign debris, salt, dust, and industrial effluent contamination. Metallic parts are visually inspected to detect loss of material due to mechanical wear or corrosion. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance. The high voltage insulators within the scope of this AMP are to be visually inspected at a frequency, determined prior to the SPEO, based on site-specific OE. The first inspections for SLR are to be completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

To meet the acceptance criterion for visual inspections, the high-voltage insulator surfaces must be free from unacceptable accumulation of foreign material, such as significant salt or dust buildup as well as other contaminants. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. Metallic parts shall be free from significant loss of materials due to pitting, fatigue, crevice, and general corrosion.

If thermography is used, acceptance criteria will be based on temperature rise above a reference temperature for the application. The reference temperature will be ambient temperature or a baseline temperature based on data from the same type of high-voltage insulator being inspected.

Trending actions are not included as part of this AMP as there is no program in place. Corrective actions will be implemented when inspection results do not meet the acceptance criteria.

The PTN High-Voltage Insulators AMP is to be implemented with initial inspections completed no later than six months prior to entering the SPEO, or no later than the last RFO prior to the SPEO.

NUREG-2191 Consistency

The PTN High-Voltage Insulators AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E7, “High-Voltage Insulators.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

NRC issued information notice IN 93-95, "Storm-Related Loss of Offsite Power Events due to Salt Buildup on Switchyard Insulators." The IN discussed salt contamination build up on insulators which caused arcing across switchyard insulators causing a plant power outage. This situation occurred at Crystal River Unit 3, Brunswick Units 1 and 2 and Pilgrim Station. The recommendations of this IN suggested the use of room temperature vulcanized silicon rubber coatings on insulators. FPL response to NRC Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule for License Renewal in letter no. L-2002-071 dated April 19, 2002 explained that "PTN Units 3 and 4 are located on a shallow bay and are not subject to a harsh salt environment primarily due to the lack of wave action. Additionally, periodic rainfall tends to wash away any salt deposits from surfaces. Consequently, the rate of contamination buildup on the insulators is not significant. Therefore, surface contamination of the PTN Units 3 and 4 insulators is not an aging effect requiring management for the period of extended operation."

Site-Specific Operating Experience

Currently, PTN utilizes polymer insulators made of silicon rubber that do not require normal cleaning. The silicon rubber exudes silicone oil that encapsulates the contaminants on the surface of the rubber. Water deposited on the surface of the rubber cannot dissolve the encapsulated contamination to create a conductive film which is what gives the silicone rubber superior contamination performance. Washing a silicone rubber housing will wash off the silicone oil along with the contamination. The silicone oil will replenish itself, but the contamination performance of the rubber is reduced until it does. The only case where washing becomes necessary is when an enormous amount of bird excrement has accumulated on the insulators. Utilizing the silicon rubber type insulators is in alignment with the recommendations cited in IN 93-95.

In addition, PTN maintenance staff regularly inspect and clean the switchyard insulators when required. Maintenance staff reviews weather conditions and other factors to determine when the insulators will be cleaned. PTN also has an equipment life cycle equipment management plan which includes inspections and cleaning of designated single point vulnerable (SPV) insulators every 10 years as well.

The PTN High-Voltage Insulators AMP is a new program for PTN to be implemented prior to the SPEO. Therefore, there is no existing site-specific OE to validate the effectiveness of this program at PTN; however, there is OE relevant to components within the scope of the PTN High-Voltage Insulators AMP.

The road along the west and south side of the PTN Switchyard was required to be moved to support EPU in the switchyard in 2012. During discussion of impacts of an AR associated with dirty motor filters on the 3B heater drain pump, it was determined there may be negative impacts on the switchyard insulators and main, auxiliary, C-Bus and Start Up transformers due to road dust accumulation on insulators. Site Area Operations was enlisted to evaluate the impact of the nearby road work on switchyard insulators. External OE advised that these types of construction sites have contaminated switchyard equipment insulation resulting in flash over. This was due to wind shift blowing dust over the switchyard resulting in contamination build up on the insulation. To minimize this effect on the switchyard equipment and transformer bushings at PTN during EPU, a wetting mechanism was utilized on the road. The road contractor utilized a water tanker and wetted the road during base preparation and completed asphalt installation on January 28, 2012; therefore, there was no further danger of dust impact. A swipe test was performed on the test bell insulator, which showed minimal surface contamination confirming that the road wetting technique during construction was effective.

Although the High-Voltage Insulators AMP is a new program, this example demonstrates when potential damage to high-voltage insulators has previously been identified, PTN has taken the appropriate measures to prevent loss of intended function. The high voltage insulators within the scope of this new AMP are to be visually inspected at a frequency, determined prior to the SPEO, based on site-specific OE. Site-specific OE, similar to this, will be used in the development of the inspection frequency of this new AMP. Additionally, this new AMP will be informed and enhanced as additional site-specific OE is accumulated to ensure excessive surface contaminants or loss of material is identified prior to a component loss of intended function. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed on a 5-year basis per NEI 14-12.

Conclusion

The PTN High-Voltage Insulators AMP is a new program that will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.4 SITE-SPECIFIC AGING MANAGEMENT PROGRAMS

This section provides the summary of the only site-specific AMP (PTN Pressurizer Surge Line Fatigue AMP) credited for managing the effects of aging at PTN. Unlike the other AMPs, this AMP is not based on NUREG-2191.

B.2.4.1 Pressurizer Surge Line Fatigue

Program Description

The PTN Pressurizer Surge Line Fatigue AMP is an existing site-specific AMP that formerly was the PTN Pressurizer Surge Line Welds Inspection Program. This AMP assesses fatigue based on the approach documented in the ASME Boiler and Pressure Vessel Code, Section XI, "Rules for In-service Inspection of Nuclear Power Plant Components, Non-Mandatory Appendix L Operating Plant Fatigue Assessment." This AMP incorporates an aging management inspection program that has been approved by the NRC. A flaw tolerance evaluation was performed specifically for PTN in order to assess the operability of the surge line by using ASME Code Section XI Appendix L methodology and to determine the successive inspection schedule for the surge line welds with a postulated surface flaw. Two bounding weld locations were evaluated in detail. The two bounding weld locations of concern are the pressurizer surge nozzle to safe-end weld and the hot leg surge nozzle-to-pipe weld. Based on a comparison of geometry, material properties and applicable loads, the results of the detailed evaluation of the two bounding locations are also applicable to all other pipe weld locations on the surge line between the two bounding weld locations. The technical analysis of the postulated flaw tolerance evaluation is provided by the NRC letter to FPL (Reference B.3.134), "Turkey Point Nuclear Generating Units 3 and 4 - Review of License Commitment for Pressurizer Surge Line Welds Inspection Program (TAC Nos. ME8717 and ME8718)." The results of the crack growth for the pressurizer surge nozzle welds and hot leg surge nozzle welds are presented in the tables below.

Table B-8
Pressurizer Surge Nozzle Crack Growth Results

Flaw Type(1)(2)	Max. Flaw Length(3)			Allowable Flaw Depth		Final Flaw Depth	Final Flaw Length(2)	Allowable Operating Period	Successive Inspection Schedule(5)
	$l/\pi D$	(Deg.)	(in.)	a/t	(in.)	(in.)	(in.)	(months)	(years)
Circumferential	0.1	36	3.91	0.75	0.96	0.650	3.900	> 564(4)	10
Axial	N/A	N/A	2.96	0.70	0.90	0.492	2.952	324(4)	10

Table B-9
Hot Leg Surge Nozzle Crack Growth Results

Flaw Type(1)(2)	Max. Flaw Length(3)			Allowable Flaw Depth		Final Flaw Depth	Final Flaw Length(2)	Allowable Operating Period	Successive Inspection Schedule(5)
	l/πD	(Deg.)	(in.)	a/t	(in.)	(in.)	(in.)	(months)	(years)
Circumferential	0.1	36	3.37	0.42	0.422	0.386	2.316	> 720	10
Axial	N/A	N/A	1.94	0.75	0.76	0.323	1.938	624(4)	10

Notes for Tables B-8 and B-9

1. The postulated initial flaw depth is 20 percent of the weld thickness (i.e., 0.201 inches) and the initial flaw length is 6 times its depth (i.e., 1.206 inches) per Appendix L guidelines.
2. A constant aspect ratio (a/l) of 1/6 is used in the crack growth analysis.
3. Flaw length is based on the inner diameter (ID).
4. Maximum flaw length is reached before the allowable flaw depth.
5. Per Appendix L, if allowable operating period is equal or greater than 10 years, the successive inspection schedule shall be equal to the examination interval listed in the PTN ASME Code Section XI schedule of ISI of the component.

Per the guidelines of ASME Code Section XI Appendix L, Table L-3420-1, for the allowable operating periods calculated in the SIA Engineering Report No. 1100756.401 (Reference B.3.146), the successive inspection schedule for surge nozzle welds is determined to be 10 years for either an axial or a circumferential postulated flaw. This inspection interval will be used for all surge line piping welds as noted in Table B-10.

Scope of Program: Element 1

All pressurizer surge line welds listed in Table B-10 will be examined in accordance with ASME Section XI, IWB for Class 1 piping welds. The aging effect managed with these inspections is cracking due to environmentally assisted fatigue (EAF). In each 10-year ISI interval during the SPEO, all surge line welds in scope will be inspected in accordance with the PTN ISI Program under Augmented and Other Programs.

Table B-10
Pressurizer Surge Line Welds Subject to
Environmental Assisted Fatigue Inspections

Unit	Weld Number	Inspection Type and Frequency
Unit 3	12”-RC-1301-1 RCS hot leg nozzle	Surface and volumetric once in 10 years
	12”-RC-1301-5 Surge pipe to pipe weld	Surface and volumetric once in 10 years
	12”-RC-1301-8 Pipe to reducer at pressurizer	Surface and volumetric once in 10 years
	14”-RC-1301-8A Reducer to safe end at pressurizer surge nozzle	Surface and volumetric once in 10 years
	14”-RC-1301-9 Safe end to nozzle	Surface and volumetric once in 10 years
Unit 4	12”-RC-1401-1’ At RCS hot leg nozzle to pipe	Surface and volumetric once in 10 years
	12”-RC-1401-2 Surge pipe to pipe weld	Surface and volumetric once in 10 years
	12”-RC-1401-4 Surge pipe to pipe weld	Surface and volumetric once in 10 years
	12”-RC-1401-7 Surge pipe to pipe weld	Surface and volumetric once in 10 years
	12”-RC-1401-8 Pipe to nozzle at pressurizer	Surface and volumetric once in 10 years
	14”-RC-1401-8A Reducer to safe end at pressurizer surge nozzle	Surface and volumetric once in 10 years
	14”-RC-1401-9 Safe end to nozzle	Surface and volumetric once in 10 years

Based on postulated flaw tolerance analysis, and per the guidelines of ASME Code, Section XI, Appendix L, Table L 3420 1, the successive inspection schedule is determined to be 10 years. This inspection interval will be used for all surge line piping welds in scope. Examination results are evaluated by qualified individuals in accordance with ASME Code Section XI acceptance criteria. Components with indications that do not exceed the acceptance criteria are considered acceptable for continued service.

Preventive Actions: Element 2

There are no specific preventive actions under this AMP to prevent the effects of aging.

Parameters Monitored or Inspected: Element 3

A surface and volumetric inservice examination will be performed on all surge line welds as indicated in Table B-10.

Detection of Aging Effects: Element 4

The degradation of surge line welds is determined by a surface and volumetric examination in accordance with the requirements of the PTN ISI Program Plan (Reference B.3.143). The frequency and scope of examination are sufficient to ensure that the aging effects are detected before the integrity of the surge line welds would be compromised.

Monitoring and Trending: Element 5

The frequency and scope of the examinations are sufficient to ensure that the EAF aging effect is detected before the intended function of these welds would be compromised. Examinations will be performed in accordance with the inspection intervals based on the results of the postulated flaw evaluation performed in accordance to the ASME Code Section XI, Appendix L methodology.

Acceptance Criteria: Element 6

Acceptance standards for the in-service inspections are identified in Subsection IWB for Class 1 components. Table IWB-2500-1 identifies references to acceptance standards listed in IWB-3500. Relevant indications found in the surge line welds that are revealed by the in-service inspections, may require additional evaluation per the requirements of ASME Code Section XI, Appendix L.

Indications that exceed the acceptance criteria are documented and evaluated in accordance with the PTN CAP. Operability of the surge line welds will require an IWB-3600 evaluation for acceptance based on engineering evaluation, repair, replacement or analytical evaluation. Repairs or replacements will be performed in accordance with ASME Code Section XI, Subsection IWA-4000 and IWA-6000.

Corrective Actions: Element 7

See Section B.1.3 for discussion on how Corrective Actions: Element 7 is addressed by this AMP.

Confirmation Process: Element 8

See Section B.1.3 for discussion on how Confirmation Process: Element 8 is addressed by this AMP.

Administrative Controls: Element 9

See Section B.1.3 for discussion on how Administrative Controls: Element 9 is addressed by this AMP.

Operating Experience: Element 10

Industry Operating Experience

Industry operating experience indicates that cracking due to fatigue can cause significant structural degradation, including the loss of pressure boundary function, to susceptible Class 1 components in nuclear power plants.

The degradation of PTN pressurizer surge line welds is determined by a surface and volumetric examination of each weld performed in accordance with the requirements of the PTN ISI Program (Reference B.3.143). Although this AMP is site-specific, PTN has performed numerous surface and volumetric examinations in accordance with ASME Section XI throughout the life of each unit. Such examinations have been proven to be effective over time in detecting cracking, which is the aging effect managed by this program. Because the ASME Code is a consensus document that has been widely used throughout the nuclear power industry over a long period, it has been shown to be effective in managing the aging effects in Class 1 components, such as cracking caused by fatigue. Therefore, industry operating experience demonstrates that the inspection techniques that this AMP credits can adequately manage the effects of cracking caused by environmentally assisted fatigue in the pressurizer surge lines.

Additional industry OE applicable to this AMP, including the ability of the selected examination techniques ability to detect cracking, is included in the OE discussion in Section B.2.3.1 for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP.

Site-Specific Operating Experience

The following review of site-specific operating experience prior to the first PEO illustrates that the Pressurizer Surge Line Fatigue AMP is effective at the identification, remediation, and management of aging effects so that the intended functions of SCs within the scope of the Pressurizer Surge Line Fatigue AMP will be maintained during the SPEO.

1. Prior to entering the PEO, all five pressurizer surge line nozzle welds on Unit 3 and all seven pressurizer surge line welds on Unit 4 received a surface and volumetric examination. No recordable indications were identified during these examinations.

2. In 2012, PTN implemented the extended power uprate (EPU) project on both units. The EPU project increased the thermal power output of each unit by approximately 15 percent. The EPU application letter from FPL to NRC "Turkey Point Nuclear Generating Units 3 and 4 - License Amendment Request for Extended Power Uprate" (ML103560169, Reference B.3.142) included an evaluation of the impact of the EPU project on the EAF analysis for the pressurizer surge lines. The results of the evaluation concluded that the calculated PTN pressurizer surge line environmentally assisted fatigue cumulative usage factors continue to exceed the acceptance criteria of 1.0. The EPU evaluation results are consistent with the fatigue analysis performed for the original license renewal application. The surge line flaw tolerance evaluation performed for the PEO was not affected by the EPU project and the PEO results remain applicable for the SPEO. For the SPEO, all pressurizer surge line welds listed in Table B-1 will continue to require surface and volumetric examination in each 10-year ISI interval during the SPEO.

   This example illustrates that the PTN design control process is capable of identifying plant modifications that could potentially impact the results of fatigue calculations performed for Class 1 components and associated aging management programs credited for the PEO.

3. During the Fall 2015 Unit 3 refueling outage, the following pressurizer surge line welds received a surface and volumetric examination:

   - 12"-RC-1301-1
   - 12"-RC-1301-8
   - 12"-RC-1301-8A

   No recordable indications were identified during these examinations. The remaining two (2) pressurizer surge line welds will be inspected prior to the end of the current 10-year ISI interval.

4. During the Spring 2016 Unit 4 refueling outage, the following pressurizer surge line welds received a surface and volumetric examination:

   - 12"-RC-1401-7
   - 12"-RC-1401-8
   - 12"-RC-1401-8A

   No recordable indications were identified during these examinations. The remaining four pressurizer surge line welds will be inspected prior to the end of the current 10-year ISI interval.

During the SPEO, OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness is assessed on a 5-year basis per NEI 14-12.

NUREG-2191 Consistency

The Pressurizer Surge Line Fatigue AMP is consistent with the ten elements of an aging management program described in NUREG-2192, Branch Technical Position A.1.2.3.

Conclusion

The PTN Pressurizer Surge Line Fatigue AMP will provide reasonable assurance that the aging effects of cracking due to environmentally assisted fatigue will be adequately managed so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

B.3 APPENDIX B REFERENCES

<u>Federal Regulations</u>

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B.3.2 *U.S. Code of Federal Regulations*, Title 10, Part 50 (10 CFR 50), “Domestic Licensing of Production and Utilization Facilities”

a. 10 CFR 50.2, “Definitions”

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

c. 10 CFR 50.55a, “Codes and Standards”

d. 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events”

e. 10 CFR 50.61a, “Alternate Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events”

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

g. 10 CFR 50.90, “Amendment of License or Construction Permit at Request of Holder”

h. 10 CFR Part 50, Appendix A, “General Design Criteria for Nuclear Power Plants”

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

j. 10 CFR Part 50, Appendix G, “Fracture Toughness Requirements”

k. 10 CFR Part 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements”

l. 10 CFR Part 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors”

B.3.3 *U.S. Code of Federal Regulations*, Title 10, Part 54, (10 CFR 54), “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”

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Appendix C

MRP-227-A Gap Analysis

Turkey Point Nuclear Plant Units 3 and 4
Subsequent License Renewal Application

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LIST OF ATTACHMENTS

C.1.0 PURPOSE

The Turkey Point (PTN) Subsequent License Renewal (SLR) Reactor Vessel Internals aging management program (AMP) is based on the existing PTN reactor vessel internals program (Reference C.4.9) which is consistent with Electric Power Research Institute (EPRI) Technical Report No. 1022863, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A),” (Reference C.4.3) and is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, “Guideline for the Management of Materials Issues” (Reference C.4.2). The staff approved the industry augmented inspection and evaluation (I&E) criteria for pressurized water reactor (PWR) reactor vessel internals components in NRC Safety Evaluation (SE), Revision 1, on MRP-227 by letter dated December 16, 2011 and the staff subsequently approved the PTN license renewal reactor vessel internals program report (Reference C.4.6), which is based on the guidance of MRP-227-A.

Because the guidelines of MRP-227-A are based on an analysis of the reactor vessel internals that considers the operating conditions up to a 60-year operating period, these guidelines are supplemented through this gap analysis that identifies enhancements to the program that are needed to address an 80-year operating period. The necessary enhancements are summarized in Section C.3.0, Conclusions. This gap analysis follows the process used to develop MRP-227-A, and identifies all time dependent parameters. These time dependent parameters are evaluated to see if they remain applicable to the 60 to 80 year operating term and what impact the extended operating period has on the conclusions of MRP-227-A.

C.2.0 ANALYSIS OF MRP-227-A DEVELOPMENT

MRP-227-A consists of I&E guidelines for managing long-term aging of pressurized water reactor (PWR) internals. These guidelines are based on a broad set of assumptions which encompass the range of current unit conditions for the U.S. fleet of PWRs, including specific analysis of Westinghouse-designed reactor vessel internals. The process used to develop the MRP-227-A recommendations is summarized by the following steps, as outlined in Appendix B of MRP-227-A;

(1) Identify internals components, materials, and environments

(2) Identify degradation screening criteria

(3) Characterize components and screen for degradation

(4) Failure modes, effects, and criticality assessment (FMECA) review

(5) Severity categorization

(6) Engineering evaluation and assessment

(7) Categorize for inspection (Primary, Expansion, Existing, No Additional Measures) and aging management strategy

(8) Preparation of MRP-227-A I&E guidelines

Each of these eight steps is evaluated for potential impact of the 80-year operating period.

C.2.1 Identify Internals Components, Materials, and Environments

A list of 120 Westinghouse reactor internals components considered in the MRP-227-A recommendations is presented in MRP-191, Table 4-4 (Reference C.4.4). This list is based on the list of 24 structures and components from WCAP-14577-R1-A (Reference C.4.8), expanded to include additional detail and specificity to aid in aging assessment.

The PTN-specific list of reactor vessel internals components being managed by the PTN Reactor Vessel Internals AMP (Reference C.4.9) is shown below.

Table C.2.1-1
Reactor Vessel Internals Components

Component	Material
Lower Internals Assembly	
Lower core plate	304 SS
Fuel alignment pins	304 SS
Lower support forging	304 SS
Lower support columns	CF8 cast SS
Lower support column bolting	316 SS
Radial keys	304 SS
Diffuser plate	304 SS
Secondary core support	304 SS
Bottom-mounted instrument column bodies	304 SS
Bottom-mounted instrumentation bases and extension bars	CF8 cast SS/304 SS
Head cooling spray nozzles	304 SS
Interfacing Components	
Clevis insert	Alloy 600
Upper core plate alignment pins	304 SS w/ Stellite hardfacing
Internals hold-down spring	304 SS
Head/vessel alignment pins	304 SS
Clevis insert bolting	X-750

Table C.2.1-1
Reactor Vessel Internals Components (Continued)

Component	Material
Lower Internals Assembly/Core Barrel Subassembly	
Core barrel flange	304 SS
Core barrel outlet nozzles	304 SS
Lower core barrel	304 SS
Upper core barrel	304 SS
Thermal shield	304 SS
Thermal shield flexures	316 SS
Lower Internals Assembly/Baffle-Former Subassembly	
Baffle and former assembly	304 SS
Baffle-former bolts	347 SS
Baffle edge bolts	316 SS
Barrel-former bolts	316 SS
Upper Internals Assembly	
Upper support plate	304 SS
Upper support ring	304 SS
Upper core plate	304 SS
Upper support column bases	CF8 cast SS
Upper support columns	304 SS
Upper support column bolting	316 SS
Upper instrumentation column (thermocouple support tubes)	304 SS / Unit 3 316 SS / Unit 4
Guide Tube Assemblies (GTA)	
GTA lower flanges	304 SS
Guide cards	304 SS
GTA C-tubes	304 SS
GTA sheaths	304 SS
GTA support pins	316 SS
GTA bolting	316 SS

This list was noted to be consistent with the component listing for Westinghouse-designed plants in MRP-191 in the FPL response to licensee action item (LAI) #2 of MRP-227- A (Reference C.4.9, Attachment 6), and the FPL response to the staffs request for additional information (RAI) 6 (Reference C.4.9, Attachment 10). There have been no modifications to the PTN reactor vessel internals components or component materials since the FPL submittal of the Turkey Point Units 3 and 4 reactor vessel internals AMP (Reference C.4.9). However, the 316 SS GTA support pins have been replaced in the past, originally constructed of X-750, and replaced due to industry operating experience with stress corrosion cracking. All other reactor vessel internals components are original. The identification of components and materials is not affected by the 80-year term and will remain applicable.

C.2.2 Identify Degradation Screening Criteria

The second step of development of MRP-227-A was to develop and apply screening criteria to identify those PWR internals component items for which the effects of age-related degradation on functionality during the license renewal term may be significant. Screening thresholds were chosen to be sufficiently conservative such that potential component items could be selected for further evaluation of the effects of aging degradation on functionality. Eight degradation mechanisms are considered relevant when assessing material aging in reactor internals. These eight degradation mechanisms and their respective screening criteria are presented below.

For each degradation mechanism, the screening parameter and the screening threshold are evaluated for potential to change due to the SPEO. The screening parameter is a component specific value such as stress or fluence. The screening threshold value is the criterion to which components are screened against such as 30 ksi or 1.3×10^{20} n/cm^2.

The degradation mechanism screening criteria used for this gap analysis are taken from MRP-175 Revision 0 (Reference C.4.5). Revision 1 of MRP-175 was published during the preparation of this gap analysis. Revision 1 includes updated screening criteria for irradiation assisted stress corrosion cracking (IASCC). Revision 0 of MRP-175 uses a step function of fluence and stress to define the threshold and the new screening criteria in Revision 1 uses a continuous curve. However, the conservative application of the step function screening criteria for the 40 to 60 year operating period (described in MRP-191) is bounding of the updated screening criteria in Revision 1 of MRP-175. This gap analysis uses a slightly more conservative application of the screening criteria, further explained below in the IASCC discussion. As the revised screening criteria of MRP-175, Revision 1, would not impact the results of this gap analysis, Revision 0 will continue to be used.

Additionally, Revision 1 of MRP-175 includes a change to the fatigue threshold, reducing it to account for environmental effects of fatigue. Per NUREG-2191 (Reference C.4.1), consideration of environmental effects on fatigue is not necessary for the reactor vessel internals, as they are not pressure boundary items. This gap analysis will use the fatigue threshold of 0.1 from Revision 0 of MRP-175. This threshold is sufficiently conservative to screen in components for potential inspections. Further fatigue analysis is available in Section 4.3.

C.2.2.1 Stress Corrosion Cracking

Section 2.1 of Reference C.4.5 identifies the screening criteria for stress corrosion cracking (SCC). Cracking due to SCC is not expected to be a significant aging mechanism for the PTN reactor vessel internals components during the subsequent period of extended operation (SPEO) because of the rigorous reactor coolant chemistry controls, as required by the PTN Water Chemistry AMP. Additionally, the PTN reactor vessel internals components are generally under low imposed stress and are fabricated from non-cold worked austenitic stainless steels (excluding the control rod guide tube support pins) further mitigating cracking due to stress corrosion. However, some component items (such as crimped locking devices and weld heat affected zones) will initially be screened in due to potentially high cold-work or weld shrinkage strains and possibly evaluated for functionality concerns. Table C.2.2-1 (taken from Table 2-1 of MRP-175 (Reference C.4.5) identifies the PWR internals screening criteria for SCC.

Table C.2.2-1
Stress Corrosion Cracking Screening Criteria for PWR Internals Materials

Material[a]	Parameter[b,c]	Threshold Value
Austenitic stainless steels	Stress <u>and</u> Material	≥ 30 ksi (207 MPa) <u>and</u> Cold-work ≥ 20% <u>or</u> Welded Locations[d]
Austenitic stainless steel welds[e]	Stress <u>and</u> Material	≥ 30 ksi (207 MPa) <u>and</u> Ferrite < 5%
Martensitic stainless steels[f]	Stress	≥ 88 ksi (607 MPa)
Martensitic precipitation-hardened (PH) stainless steels[f]	Stress	≥ 88 ksi (607 MPa)
Austenitic PH stainless steels	Stress <u>and</u> Material	≥ 70 ksi (483 MPa) <u>and</u> Surface cold-work
	Hot-headed <u>or</u> shot-peened bolting that meet the stress criterion are to be evaluated for SCC.	
Cast austenitic stainless steel (CASS)[e]	Stress <u>and</u> Material[g]	≥ 35 ksi (241 MPa) <u>and</u> Ferrite < 5%
Austenitic Ni-base alloys[h]	Stress	≥ 30 ksi (207 MPa)
Austenitic Ni-base welds[h]	Stress	≥ 35 ksi (241 MPa)
Austenitic PH Ni-base welds[h] (Alloy X-750)	Stress[i]	≥ 100 ksi (689 MPa)
	AH and BH condition considered more susceptible than HTH condition.	
Austenitic PH Ni-base (Alloy X-718)	Stress[i]	≥ 130 ksi (896 MPa)
Co-base alloys	Alloys not susceptible in PWR internals locations.	

Notes for Table C.2.2-1

a. The specific alloys applicable to these material categories are provided in Section 1 (Table 1-1) of MRP-175. Unless noted there is no quantifiable difference in screening threshold values among low carbon (L-grades), cold-worked, or solution-annealed materials.
b. Fluence or flux dependencies are accounted for in the IASCC table (Table C.2.2-2).
c. Synergistic effects of identified stress and material are requirements where noted. Temperature of PWR internals is sufficient, so no screening threshold value is necessary. Stress is defined as peak stress, whether for an item (e.g., plate, pin, flange, etc.) or bolt.
d. Multi-pass full-penetration, partial-penetration, or fillet joint types are of concern due to potentially high weld shrinkage strains in the heat-affected zone. Small weld joint types such as tack or plug welds are excluded.
e. A potential concern exists that SCC could affect austenitic stainless steel welds and CASS materials that meet or exceed both the stress criterion and the thermal aging embrittlement criteria (Table C.2.2-5).
f. Martensitic stainless steels not subject to gamma heating with tempers > 1125°F (607°C) and martensitic PH stainless steels not subject to gamma heating with tempers > 1100°F (593°C) generally are not considered susceptible to SCC. However, a potential concern exists that SCC could affect locations even where the tempering temperature was above these values primarily because of the very slow kinetics of the thermal aging embrittlement mechanism (Table C.2.2-5), which could take several tens of years for embrittlement to become significant, and its sensitivity to temperature in the range applicable to PWR internals.
g. Ferrite value chosen by analogy with austenitic stainless steel welds.
h. Specifically Alloys 600, 182 and 82.
i. Surface condition is critical to SCC susceptibility.

The screening criteria for SCC is not time dependent. The established threshold values are applicable to an extended period of 80 years of operation and the thresholds for identifying susceptibility to SCC will remain unchanged. Additionally, the screening parameters for SCC are also not time dependent. The material properties and component stresses are not impacted by extended operation. Therefore, the screening results for components subject to SCC will not change during the 80-year term.

C.2.2.2 Irradiation Assisted Stress Corrosion Cracking

Section 2.1 of Reference C.4.5 identifies the screening criteria for irradiation assisted stress corrosion cracking (IASCC). For component items beyond a lower limit screening fluence of 3 dpa (2.0 x10^{21} n/cm^2, E >1.0 MeV), irradiation assisted stress corrosion cracking (IASCC) is a potential age-related degradation mechanism. Screening depends on stress (operating and residual) level and expected fluence. Table C.2.2-2 (taken from Table 2-2 of MRP-175) identifies the PWR Internals screening criteria for IASCC. Reference C.4.5 refers to dose and fluence interchangeably. However, throughout this document, fluence is used exclusively.

Table C.2.2-2
Irradiation Assisted Stress Corrosion Cracking
Screening Criteria for PWR Internals Materials

Material[a]	Parameter[b]	Threshold Value[c]
All Alloys	Stress and Fluence	If, Fluence< 2.0 x 10^{21} n/cm^2 (E> 1.0 MeV) (<3 dpa) See SCC criteria (Table C.2.2-1). IASCC not considered applicable.
		≥ 89 ksi (616 MPa) and 2.0 x 10^{21} n/cm^2 (E> 1.0 MeV) (3 dpa)
		≥ 62 ksi (425 MPa) and 6.7 x 10^{21} n/cm^2 (E> 1.0 MeV) (10 dpa)
		≥ 46 ksi (315 MPa) and 1.3 x 10^{22} n/cm^2 (E> 1.0 MeV) (20 dpa)
		≥ 30 ksi (205 MPa) and 2.7 x 10^{22} n/cm^2 (E> 1.0 MeV) (40 dpa)

Notes for Table C.2.2-2

a. The specific applicable alloys are provided in Section 1 (Table 1-1) of MRP-175. In general, only austenitic stainless steel wrought materials and welds will receive sufficient doses for screening consideration. Unless noted there is no quantifiable difference in screening threshold values among low carbon (L-grades), cold-worked, or solution-annealed materials.

b. Stress is defined as peak stress, whether for an item (e.g., plate, pin, flange, etc.) or bolt.

c. Example stress and fluence values provided in table are from Appendix B, Figure B-3 of MRP-175; values for other stresses and doses can be obtained from this figure.

The IASCC screening threshold values are not time dependent, the established threshold values are applicable to an extended period of 80 years of operation and the thresholds for identifying susceptibility to IASCC will remain unchanged. However, the screening parameters are time dependent. Components will receive additional fluence over the 60 to 80 year period and may potentially exceed the threshold for IASCC, requiring new inspections for the 80-year period of operation.

C.2.2.3 Wear

Section 2.4 of Reference C.4.5 identifies the screening criteria for wear. The only known aging degradation mechanism that results in significant loss of material is wear due to mechanical abrasion in circumstances where items are physically in contact and able to move in relation to each other. Loss of material due to wear is not considered a potential aging effect for bolted items provided the bolts continue to maintain sufficient preload, or do not sever as a result of cracking.

Wear is influenced by a number of parameters and no clear screening thresholds exist. Screening is performed by evaluating locations where relative motion might occur, where clamping force is required, and with bolted or spring locations where stress relaxation and irradiation induced creep (SR/IC) is screened, as applicable.

Table C.2.2-3
Wear Screening Criteria for PWR Internals Materials

Material[a]	Parameter[b]	Threshold
All Alloys	Relative motion	Locations where this might occur between component items.
		Example: control rod guide tubes
	Clamping force	Locations where this is required
		Example: mating ledge between internals and RV.
	Bolted or spring items	Locations where SR/IC is screened as applicable
		Example: baffle-to-former bolts

Notes for Table C.2.2-3

a. The specific applicable alloys are provided in Section 1 (Table 1-1) of MRP-175. Unless noted, there is no quantifiable difference in screening values among low carbon (L-grades), cold-worked, or solution-annealed materials.

b. Fluence or flux dependencies are accounted for in the SR/IC table (Table C.2.2-8).

Wear is primarily a design dependent aging effect and independent of time; however, the thresholds for wear are time dependent in locations where SR/IC applicability is considered. The wear thresholds have potential to change when considering an 80-year period of operation. The screening parameters (excluding SR/IC) are not time dependent. While wear will increase with time, the screening parameters only consider susceptibility based on design.

C.2.2.4 Fatigue

Section 2.1 of Reference C.4.5 identifies the applicable screening criteria for fatigue; however, there is no clearly defined industry criteria to screen reactor vessel internals components for fatigue. A time-limited aging analysis is used to evaluate fatigue in Section 4.3. In addition to the analysis, reactor vessel internals components are inspected for cracking due to fatigue based on a conservative cumulative usage factor (CUF) screening threshold. A CUF of greater than or equal to 0.1 (calculated at the end of the subsequent license renewal period) is used to screen reactor vessel internals components for inspection. In addition, all bolted or spring items for which SR/IC are screened, as applicable, might also be susceptible to fatigue and screen in. Table C.2.2-4 (taken from Table 2-3 of MRP-175) identifies the PWR internals screening criteria for fatigue.

Table C.2.2-4
Fatigue Screening Criteria for PWR Internals Materials

<table>
<tr><th rowspan="2">Material[a]</th><th colspan="2">Criteria</th></tr>
<tr><th>Parameter[b]</th><th>Threshold Value</th></tr>
<tr><td rowspan="4">All alloys</td><td>CUF[c]</td><td>≥0.1</td></tr>
<tr><td>Bolted or spring items</td><td>Locations where SR/IC is screened as applicable.</td></tr>
<tr><td colspan="2">As material aging concerns with irradiation embrittlement (IE), SR/IC, etc. occur; low cycle fatigue (LCF) and/or high cycle fatigue (HCF) might become an issue.</td></tr>
<tr><td colspan="2">In some instances, fatigue life was alternatively qualified through testing. These component items should be initially screened in for potential fatigue concerns and evaluated.</td></tr>
</table>

Notes for Table C.2.2-4

a. The specific applicable alloys are provided in Section 1 (Table 1-1) of MRP-175. Unless noted there is no quantifiable difference in screening threshold values among low carbon (L-grades), cold-worked, or solution-annealed materials.
b. Fluence or flux dependencies are accounted for in the SR/IC table (Table C.2.2-8).
c. CUF is to be calculated at the end of original plant license (i.e., 40 years) based on the analysis in Section 4.3.

The fatigue screening criteria are primarily independent of time, however, the threshold values for fatigue are assumed to be time dependent in locations where SR/IC applicability is considered. The fatigue threshold values have potential to change when considering an 80-year period of operation. The screening parameters are time dependent and components have potential to exceed the threshold for fatigue, requiring new inspections for the 80-year period of operation.

C.2.2.5 Thermal Embrittlement

Section 2.2 of Reference C.4.5 identifies the applicable screening criteria for thermal embrittlement. All martensitic SS and martensitic PH SS component items are considered susceptible to thermal embrittlement. Cast austenitic stainless steel (CASS) and austenitic stainless steel (SS) welds are potentially susceptible to thermal embrittlement (TE).

Criteria for CASS materials are based on the type of casting (centrifugal vs. static), ferrite content, and molybdenum content (for static castings only). Some CASS locations will be screened in for further evaluation of a potential synergistic effect of fluence on thermal embrittlement proposed by the NRC based on the irradiation embrittlement screening criteria shown in Table C.2.2-6.

Criteria for austenitic SS welds are based on static CASS castings, due to similarity in composition, and ferrite and molybdenum contents. Some austenitic SS weld locations will be screened in for further evaluation of a potential synergistic effect of flux or fluence on TE proposed by the NRC based on the irradiation embrittlement screening criteria shown in Table C.2.2-6. Table C.2.2-5 (taken from Table 2-4 of MRP-175) summarizes the screening criteria for thermal embrittlement.

Table C.2.2-5
Thermal Embrittlement Screening Criteria for PWR Internals Materials

Material[a,b]	Criteria	
	Parameter	Threshold Value
Austenitic SS Austenitic PH SS Austenitic Ni-Base Alloys Austenitic PH Ni-Base Alloys Co-Base Alloys	Thermal embrittlement is not applicable to these materials	
CASS (centrifugal castings)	Ferrite	>20%
CASS (static castings)	Molybdenum and Ferrite	≤0.50% and >20%
	Molybdenum and Ferrite	>0.50% and >14%
Austenitic SS Welds[c]	Molybdenum and Ferrite	≤0.50% and >20%
	Molybdenum and Ferrite	>0.50% and >14%
	Thermal embrittlement is not anticipated as an issue due to ASME Code procurement requirements for low levels of ferrite (5-15%) and low Mo levels.	
Martensitic SS[d]	All component items considered susceptible to TE	
Martensitic PH SS[d]	All component items considered susceptible to TE	

Notes for Table C.2.2-5

a. The specific alloys applicable to these material categories are provided in Section 1 (Table 1-1) of MRP-175. Unless noted there is no quantifiable difference in screening threshold values among low carbon (L-grades), cold-worked, or solution-annealed materials.

b. Increased susceptibility to SCC expected due to TE of all susceptible materials. Also, see Table C.2.2-1, note e.

c. The same criteria suggested for static castings have been applied to austenitic stainless steel welds.

d. Temperature of PWR internals is sufficient, so no screening value is necessary, particularly those locations subject to significant gamma heating.

The thermal embrittlement screening criteria are independent of time, except for potential synergistic effects of irradiation embrittlement which has potential to change when considering an 80-year period of operation. The screening parameters and threshold values are not time dependent and will remain unchanged for an 80-year operating period.

C.2.2.6 Irradiation Embrittlement

Section 2.2 of Reference C.4.5 identifies the screening criteria for irradiation embrittlement (IE). Irradiation embrittlement is only relevant to materials that are used in relatively high fluence locations (e.g. austenitic SS, austenitic SS welds, and CASS). If other materials are used in a location that exceeds the austenitic stainless steel criterion, they also are considered potentially susceptible to irradiation embrittlement. Table C.2.2-6 (taken from Table 2-5 of MRP-175) summarizes the screening criteria for irradiation embrittlement.

Table C.2.2-6
Irradiation Embrittlement Screening Criteria for PWR Internals Materials

<table>
<tr><th rowspan="2">Material[a]</th><th colspan="2">Criteria</th></tr>
<tr><th>Parameter</th><th>Threshold Value</th></tr>
<tr><td>Austenitic PH SS
Austenitic Ni-Base Alloys
Austenitic PH Ni-Base Alloys
Martensitic SS
Martensitic PH SS
Co-Base Alloys</td><td colspan="2">These materials are used in relatively low fluence locations; therefore, IE is not an applicable age-related degradation mechanism for component items fabricated with these alloys.[b]</td></tr>
<tr><td>Austenitic SS</td><td>Fluence</td><td>$\geq 1 \times 10^{21}$ n/cm^2 (E > 1.0 MeV) (≥1.5 dpa)</td></tr>
<tr><td rowspan="2">Austenitic SS Welds
CASS</td><td>Fluence</td><td>$\geq 6.7 \times 10^{20}$n/cm^2 (E > 1.0 MeV) (≥1 dpa)</td></tr>
<tr><td colspan="2">Lower screening value used to account for large initial fracture toughness variability with these materials and possible synergistic effect on thermal aging embrittlement.</td></tr>
</table>

Notes for Table C.2.2-6

a. The specific alloys applicable to these material categories are provided in Section 1 (Table 1-1) of MRP-175. Unless noted there is no quantifiable difference in screening threshold values among low carbon (L-grades), cold-worked, or solution-annealed materials.

b. If one of these materials is used in a location that exceeds the fluence criterion for austenitic stainless steel, the same criterion would apply for screening.

The irradiation embrittlement threshold values are independent of time and will remain unchanged for an 80-year operating period. However, the screening parameters are time dependent. Components will receive additional fluence over the 60 to 80 year period and may potentially exceed the threshold for irradiation embrittlement, requiring new inspections for the 80-year period of operation.

C.2.2.7 Void Swelling

Section 2.2 of Reference C.4.5 identifies the screening criteria for void swelling. Only austenitic SS and austenitic SS welds are typically used in locations where the combined screening criteria for fluence and temperature will be exceeded. If other materials are used in locations that exceed the criteria, they also are potentially susceptible to void swelling. Table C.2.2-7 (taken from Table 2-6 of MRP-175) summarizes the screening criteria for void swelling.

Table C.2.2-7
Void Swelling Criteria for PWR Internals Materials

Material[a]	Criteria	
	Parameter	**Threshold Value**
CASS Austenitic PH SS Austenitic Ni-Base Alloys Austenitic PH Ni-Base Alloys Martensitic SS Martensitic PH SS Co-Base Alloys	These materials are used in relatively lower temperature and fluence locations; therefore, void swelling is not an applicable age-related degradation mechanism for component items fabricated with these alloys.[b]	
Austenitic SS Austenitic SS Welds	Temperature and Fluence	≥ 608°F (320°C) and ≥ 1.3 X 10^{20} n/cm^2 (E > 1.0 MeV) (≥ 20 dpa)

Notes for Table C.2.2-7

a. The specific alloys applicable to these material categories are provided in Section 1 (Table 1-1) of MRP-175. Unless noted there is no quantifiable difference in screening threshold values among low carbon (L-grades), cold-worked, or solution-annealed materials.

b. If one of these materials is used in a location that exceeds the fluence criterion for austenitic stainless steel, the same criterion would apply for screening.

The void swelling threshold values are independent of time and therefore, will remain unchanged for an 80-year operating period. However, the screening parameters are time dependent. Components will receive additional fluence over the 60 to 80 year period and may potentially exceed the threshold for void swelling.

C.2.2.8 Irradiation Induced Stress Relaxation/Creep

Section 2.3 of Reference C.4.5 identifies the screening criteria for irradiation induced stress relaxation and creep (SR/IC). Loss of mechanical closure integrity may result from SR/IC of those component items where maintaining a preload is important to the structural integrity function of the PWR internals (i.e. bolting or springs). Neutron fluence, temperature, and the degree of preloading are the key parameters. The identified potential materials and age-related degradation mechanisms of concern for loss of mechanical closure integrity are summarized in Table C.2.2-8 (taken from Table 2-7 of MRP-175).

Table C.2.2-8
Thermal and Irradiation Induced Stress Relaxation and Creep Screening Criteria for PWR Internals Materials

Materials[a]	Criteria	
	Parameter	Threshold Value
Thermal SR		
All Alloys	Bolts or springs	All locations
	Applies to component items that require preload for functionality.	
Irradiation-Enhanced SR and IC		
All Alloys	Fluence	≥ 1.3×10^{20} n/cm^2 (E > 1.0 MeV) (≥ 0.2 dpa)
	Applies to all bolted or spring locations. Complex interactions when void swelling occurs.	

Notes for Table C.2.2-8

a. The specific applicable alloys are provided in Section 1 (Table 1-1) of MRP-175. Unless noted there is no quantifiable difference in screening thresholds among low carbon (L-grades), cold-worked, or solution-annealed materials.

The irradiation induced stress relaxation and creep threshold values are independent of time. While interactions with void swelling are time dependent and create complex interactions, it does not impact whether or not a component will screen in for irradiation induced stress relaxation and creep. The threshold values will remain unchanged for an 80-year operating period. The screening parameters are time dependent. Components will receive additional fluence over the 60 to 80 year period and may potentially exceed the threshold for irradiation induced stress relaxation and creep, requiring new inspections for the 80-year period of operation.

C.2.2.9 Summary

Based on the above evaluation, Table C.2.2-9 summarizes the potential for screening threshold values and screening parameters to change for the subsequent period of extended operation.

Table C.2.2-9
Potential for Change When Considering the Subsequent Period of Extended Operation

Aging Effect/Mechanism	Parameters	Threshold Value
SCC	No	No
IASCC	Yes	No
Wear	Yes[a]	Yes[a]
Fatigue	Yes[b]	Yes[a]
TE	Yes[c]	Yes[c]
IE	Yes	No
VS	Yes	No
SR/IC	Yes	No

Notes for Table C.2.2-9

a. The potential for change represents a variable screening threshold dependent on the screening results for stress relaxation and creep. The screening parameters only have potential to change because they are indirectly tied to the screening parameters of stress relaxation and creep. Changes only have potential to occur if new components are screened in for stress relaxation and creep.

b. This represents the same conditions as note a with the additional variable of the direct screening parameters for fatigue being time dependent. New components could potentially be added based on changes to the fatigue evaluation or the stress relaxation and creep screening results.

c. The potential for change represents a variable screening threshold dependent on the screening results for irradiation embrittlement. The screening parameters only have potential to change because they are indirectly tied to the screening parameters of irradiation embrittlement. Changes only have potential to occur if new components are screened in for irradiation embrittlement.

All screening thresholds with potential to change are based on the screening results of other aging effects. The primary potential for change is the screening parameters which change over time (cumulative fluence and cumulative usage factor). For IASCC, irradiation embrittlement, void swelling, and stress relaxation and creep, the parameter which will change over time is fluence. For fatigue, the parameter which will change over time is the cumulative usage factor.

C.2.3 Characterize Components and Screen for Degradation

The third step of the process is to evaluate the components identified in Section C.2.1 against the screening criteria outlined in Section C.2.2 and documented in MRP-175 (Reference C.4.5). Table C.2.3-1 outlines the initial screening parameters (applicable for the 40-to-60 year operating period and taken from Reference C.4.9) for the components listed in Table C.2.1-1 and the time-dependent screening parameters. The neutron fluence regions are defined in Table C.2.3-2 consistent with the definitions in Reference C.4.4.

Table C.2.3-1
Component Screening for CUF and Fluence
(40–60 Year Operating Period)

Component	CUF > 0.1	Neutron Fluence Region		Component	CUF > 0.1	Neutron Fluence Region
Lower Core Plate	Yes	Region 5		Upper Core Barrel	No	Region 3
Fuel Alignment Pins	No	Region 5		Thermal Shield	No	Region 4
Lower Support Forging	No	Region 1		Thermal Shield Flexures	Yes	Region 4
Lower Support Columns	No	Region 5		Baffle and Former Assembly (baffle plates)	Yes	Region 6
Lower Support Column Bolting	Yes	Region 5		Baffle-Former Bolts	Yes	Region 6
Radial Keys	No	Region 1		Baffle Edge Bolts	Yes	Region 6
Diffuser Plate	No	Region 1		Barrel-Former Bolts	Yes	Region 6
Secondary Core Support	No	Region 1		Upper Support Plate	No	Region 1
BMI Column Bodies	Yes	Region 5		Upper Support Ring	Yes	Region 1
BMI Bases and Extension Bars	No	Region 5		Upper Core Plate	Yes	Region 4
Head Cooling Spray Nozzles	No	Region 1		Upper Support Column Bases	No	Region 3
Clevis Insert	No	Region 1		Upper Support Columns	No	Region 3
Upper Core Plate Alignment Pins	No	Region 3		Upper Support Column Bolting	No	Region 3
Internals Hold-Down Spring	No	Region 1		Upper Instrumentation Column	No	Region 1
Head/Vessel Alignment Pins	No	Region 1		GTA Lower Flanges	Yes	Region 3
Clevis Insert Bolting	No	Region 1		Guide Cards	Yes	Region 1
Flux Thimble Tubes	No	Region 5		GTA C-Tubes	No	Region 3
Core Barrel Flange	No	Region 1		GTA Sheaths	No	Region 3
Core Barrel Outlet Nozzles	Yes	Region 1		GTA Support Pins	Yes	Region 3
Lower Core Barrel	No	Region 4		GTA Bolting	No	Region 1

Table C.2.3-2
Fluence Regions

Region 1	$\phi t < 1x10^{20}$ n/cm^2
Region 2	$1x10^{20}$ n/cm^2 (0.15 dpa) $\leq \phi t < 7x10^{20}$ n/cm^2
Region 3	$7x10^{20}$ n/cm^2 (1 dpa) $\leq \phi t < 1x10^{21}$ n/cm^2
Region 4	$1x10^{21}$ n/cm^2 (1.5 dpa) $\leq \phi t < 1x10^{22}$ n/cm^2
Region 5	$1x10^{22}$ n/cm^2 (15 dpa) $\leq \phi t < 5x10^{22}$ n/cm^2
Region 6	$5x10^{22}$ n/cm^2 (75 dpa) $\leq \phi t$
ϕt (fluence) is for neutron energies with E>1 MeV	

Fatigue is evaluated for an 80-year operating period at PTN in Section 4.3. The results of the analysis in Section 4.3 indicate that the analysis performed for the initial (60-year operating period) license renewal remains bounding and there are no changes to the cumulative usage factors. However, the CUF values used for the initial license renewal were based on generic, industry representative values. In PTN's extended power uprate (EPU) license amendment request (LAR) (Reference C.4.7) several reactor vessel internals CUF values were identified as applicable to PTN. These values are outlined in the gap analysis summary table, included as Attachment C1. These values were not PTN specific, but cited as applicable and taken from an international plant with the same design. The EPU LAR included CUF values for reactor vessel internals components which are subject to aging management review. Of these components, five components have CUF values greater than or equal to 0.1 which were identified as being below 0.1 in the initial license renewal implementation screening shown in Table C.2.3-1. These components are listed as follows:

- Lower support columns – [ ]
- Clevis insert – [ ]
- Radial keys – [ ]
- Upper core plate alignment pins – [ ]
- Upper support plate – [ ]

These five components are screened in for fatigue for the 80-year period of operation.

Neutron fluence values which are representative of Westinghouse designed plants have been developed for an 80 year operating period and are incorporated in the gap analysis summary included as Attachment 1. The results of reactor vessel internals fluence analysis show an increase in neutron fluence region (Table C.2.3-2) for nine PTN reactor vessel internals components. The components which experience neutron fluence region increase are presented in Table C.2.3-3. Brackets are used to identify proprietary information.

In addition to the fluence region changes presented in Table C.2.3-3, several components were found to be in a lower neutron fluence region. However, to remain conservative, all components which were analyzed to be in a lower neutron fluence region continue to be treated as they were in the initial license renewal AMP.

Table C.2.3-3
Fluence Accumulation and Screening

Component	60-Year Fluence	80-Year Fluence
Fuel Alignment Pins	Region 5	Region [ ]
Diffuser Plate	Region 1	Region [ ]
Flux Thimble Tubes	Region 5	Region [ ]
Lower Core Barrel	Region 4	Region [ ]
Upper Support Column Bases	Region 3	Region [ ]
Upper Support Column Bolting	Region 3	Region [ ]
GTA Lower Flanges	Region 3	Region [ ]
Guide Cards	Region 1	Region [ ]
GTA Support Pins	Region 3	Region [ ]

Screening for the five fluence related degradation mechanisms is largely based on these changes. As the fluence data is only presented with ranges, and the screening thresholds are discrete values, any fluence change which may exceed a screening threshold is screened in.

IASCC

The screening criteria outlined in Table C.2.2-2 outlines a step increase in fluence threshold based on the effective stress the component is exposed to. However, the only stress information currently available is whether or not a component is subject to greater than 30 ksi, the lowest stress considered for IASCC. To remain conservative, when screening new components, if a component is exposed to an effective stress greater than 30 ksi, it will be considered to have an effective stress greater than 89 ksi. With this assumption, a fluence threshold of 2.0 X 10^{21} will be applied to all components not previously screened for IASCC, which have an effective stress greater than 30 ksi.

The fluence threshold of 2.0 x 10^{21} is within Region 4 (1 x 10^{21} to 1 x 10^{22}). The components of interest which might screen in for IASCC meet the following criteria:

- Exceed effective stress threshold of 30 ksi
- Neutron fluence region 4 or greater for the 80 year period
- Did not previously screen in for IASCC

Based on these criteria, the following components screen in for IASCC:

- Upper core plate
- Upper support column bases
- Upper support column bolting
- GTA lower flanges
- GTA support pins

The GTA bases, bolting, lower flanges, and support pins all increased from fluence region 3 to fluence region 4 and had an effective stress of greater than 30 ksi. The upper core plate remains in region 4 but is expected to receive additional fluence. Previously, the upper core plate was dispositioned as having fluence and stress levels which exceed the screening threshold values, but not in an intersecting locations (Reference C.4.9). Absent specific details of this analysis, it is assumed that the increased fluence levels cause the fluence threshold value to be exceeded in the high stress areas of the upper core plate.

Irradiation Embrittlement

The screening criteria outlined in Table C.2.2-6 establishes separate fluence threshold values for CASS and austenitic stainless steel. All CASS components screened in for IE during the initial license renewal. As such, only the screening for austenitic stainless steel needs to be examined. The fluence threshold value of 1.0 X 10^{21} corresponds to the lower bound of fluence region 4. There is no potential for a component to newly exceed the threshold value without changing fluence regions, as the threshold aligns with the fluence region 4 lower bound. The only components which may newly screen in for IE are components previously placed in a region lower than region 4 and placed in region 4 or greater for 80 years. These components are as follows:

- Upper support column bolting
- GTA lower flanges
- GTA support pins

Additionally, any component previously placed in fluence region 4 but not screened in for IE is evaluated, due to potential for the fluence to exceed the threshold value but remain in fluence region 4. Upon review of the initial license renewal screening results, all components which were in fluence region 4 for the initial license renewal screening were previously screened in for IE.

Void Swelling

The screening criteria outlined in Table C.2.2-7 uses a fluence threshold value of 1.3 X 10^{22} and a temperature threshold value of 608°F. The fluence threshold value is within fluence region 5. The components which may newly screen in for VS are components previously placed in a fluence region lower than region 5 and are placed in region 5 or greater for 80 years. The lower core barrel is the only component which fits this criteria. However, this component is indicated as "T-cold" in Table 4-6 of Reference C.4.4. While the definition of "T-cold" is not given, it is stated that components with a temperature of in excess of 608°F are stated as such. While the lower core barrel exceeds the fluence threshold value for VS, it does not reach the temperature threshold value and does not screen in.

Additionally, any component previously placed in fluence region 5 but not screened in for VS will be evaluated, due to potential for the fluence to exceed the threshold value but remain in fluence region 5. Upon review of the initial license renewal screening results, all components which were in fluence region 5 for the initial license renewal screening and remained in fluence region 5 were previously screened in for VS. Therefore, there are no newly screened in components for the VS degradation mechanism.

SR/IC

The screening criteria outlined in Table C.2.2-8 uses a fluence threshold value of 1.3 X 10^{20} and for the component to be sprung or bolted requiring preload. The fluence threshold is within fluence region 2. The components which may newly screen in for SR/IC are components previously placed in region 1 and are placed in region 2 or greater for 80 years. Three components fit the fluence criteria to be newly screened in (diffuser plate, guide cards); however, none of these components require preload. Therefore, there are no newly screened in components for the SR/IC degradation mechanism.

C.2.4 Failure Modes, Effects, and Criticality Analysis (FMECA) Review

The fourth step in the process is to evaluate the failure likelihood and consequence (damage likelihood) associated with the identified reactor vessel internals components. The analytical process used to evaluate components for the impact of failure on operations, the system, and surrounding components is outlined in Section 6.2 of Reference C.4.4. A team of Westinghouse experts was assembled and asked to consider components that screened in for one or more of the various degradation mechanisms, as well as those that did not screen in for any degradation mechanisms. The end results were a FMECA ranking (Groups 0, 1, 2 or 3) for the components during the 60-year period of operation as reported in MRP-191 (Reference C.4.4). The logic used to arrive at the FMECA ranking is summarized in Table C.2.4-1 taken from Table 6-4 of Reference C.4.4.

Table C.2.4-1
FMECA Grouping

Failure Likelihood	Consequence (Damage Likelihood)		
	Low	**Medium**	**High**
High	2	3	3
Medium	1	2	3
Low	1	1	2
None	0	0	0

An expert panel was not assembled to conduct a FMECA for the 60 to 80 year gap analysis; however, the FMECA inputs (failure likelihood and consequence) and logic for the 60-year period of operation were utilized to evaluate the impact of the newly screened in component degradation mechanisms for the 80-year period of operation.

The consequence rankings for components remain consistent with the 40- to 60-year operating period. However, the failure likelihood might change based on newly screened in degradation mechanisms, or an increase in the severity of a degradation mechanism. A review of operating experience, available in SLRA Section B.2.3.7, informs which components are subject to an increase in the severity of a degradation mechanism sufficient to warrant an increase in failure likelihood.

Five components newly screened in for fatigue, five for IASCC, and three for IE during the 80-year period of operation. Two components have operating experience indicating sufficient increase in the severity of a degradation mechanism to warrant a reevaluation of FMECA score for the 80-year period of operation. Table C.2.4-2 outlines the 80-year operating period FMECA results for these components. Bolded items in Table C.2.4-2 identify where these FMECA results deviate from those presented in Table 6.5 of Reference C.4.4.

Table C.2.4-2
FMECA Results

Assembly	Sub-Assembly	Component	Material	Imminent Consequences of Failure	Screened-In Degradation Mechanisms	Likelihood of Failure (L, M, H)	Likelihood of damage	FMECA Group
Lower internals assembly	Lower core plate and fuel alignment pins	Fuel alignment pins	304 SS	None	IASCC, Wear, IE, VS	**H**	L	2
Lower internals assembly	Lower support column assembly	Lower support columns	CF8 CASS	Significant economic impact	IASCC, **fatigue**, TE, IE, VS	M	L	1
Lower internals assembly	Radial Support Keys	Radial keys	304 SS	Significant economic impact	SCC welds, wear, **fatigue**	L	L	1
Interfacing Components	Interfacing Components	Clevis insert	Alloy 600	Significant economic impact	Wear, **fatigue**	L	L	1
Interfacing Components	Interfacing Components	Clevis insert bolting	X-750	Significant economic impact	SCC, wear	H	L	2
Interfacing Components	Interfacing Components	Upper core plate alignment pins	304 SS **w/ stellite hardfacing**	None	SCC welds, wear, **fatigue**	M	L	1
Upper Internals Assembly	Upper Support Plate Assembly	Upper support plate	304 SS	Significant economic impact	**fatigue**	**L**	**L/M**	**1**
Upper Internals Assembly	Upper core plate and fuel alignment pins	Upper core plate	304 SS	Precludes a safe shutdown, significant economic impact	**IASCC**, wear, fatigue, IE	L	M	1
Upper Internals Assembly	Upper support column assemblies	Upper support column bases	CF8 CASS	Significant economic impact	SCC, **IASCC,** TE, IE	L	M	1
Upper Internals Assembly	Upper support column assemblies	Upper support column bolting	316 SS	Significant economic impact	**IASCC**, wear, fatigue, **IE**, SR/IC	L	M	1
Upper Internals Assembly	Control Rod Guide Tube Assemblies and Flow Downcomer	GTA lower flange	304 SS	Significant economic impact	**IASCC**, SCC welds, fatigue, **IE**	L	M	1
Upper Internals Assembly	Control Rod Guide Tube Assemblies and Flow Downcomer	GTA support pins	316 SS	None	**IASCC**, Wear, fatigue, **IE**, SR/IC	L	M	1

The fuel alignment pins were placed in FMECA Group 1 for the 60-year period of operation with a Low failure likelihood and Low failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included IASCC, wear, IE and void swelling. Industry operating experience (OE) (Reference C.4.11) indicates accelerated wear of fuel alignment pins (304 SS with Malcomized surface treatment) attached to the upper and lower core plates at a number of Westinghouse designed plants, including Turkey Point Units 3 and 4. Based on these indications, wear of the fuel alignment pins would increase the failure likelihood score from Low to High. The Low failure consequence ranking would remain unchanged since the fuel alignment pins present neither economic nor safety consequences. This would place the fuel alignment pins in FMECA Group 2 for the 80-year period of operation.

The lower support columns were placed in FMECA Group 1 for the 60-year period of operation with a Medium failure likelihood and Low failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included IASCC, TE, IE and void swelling. The estimated CUF for the lower support columns is [ ], which is right at the threshold criteria for fatigue. As such, the inclusion of fatigue in the list of potential degradation mechanisms is not considered to impact the Medium failure likelihood ranking. The low failure consequence ranking would also remain unchanged because failure of the lower support columns presents economic but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The lower support columns would remain in FMECA Group 1 for the 80-year period of operation.

The radial keys were placed in FMECA Group 1 for the 60-year period of operation with a Low failure likelihood and Low failure consequence rankings. Wear and SCC are currently the only degradation mechanisms that screened in during the 60-year period of operation. The estimated CUF for the radial keys is [ ], just slightly above the 0.1 criteria for fatigue. As such, the inclusion of fatigue in the list of potential degradation mechanisms is not considered to impact the Low failure likelihood ranking. The low failure consequence ranking would also remain unchanged since failure of the radial keys presents economic, but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The radial keys would remain in FMECA Group 1 for the 80-year period of operation.

The clevis inserts were placed in FMECA Group 1 for the 60-year period of operation with a Low failure likelihood and Low failure consequence rankings. Wear is currently the only degradation mechanism that screened in during the 60-year period of operation. The estimated CUF for the clevis inserts is [ ], just slightly above the 0.1 criteria for fatigue. As such, the inclusion of fatigue in the list of potential degradation mechanisms is not considered to impact the Low failure likelihood ranking. The low failure consequence ranking would also remain unchanged since failure of the clevis inserts presents economic but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The clevis inserts would remain in FMECA Group 1 for the 80-year period of operation.

The clevis insert bolting (X-750) was placed in FMECA Group 2 for the 60-year period of operation with a High failure likelihood and Low failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included SCC and wear.

Industry OE (SLRA Section B.2.3.7) indicates the SCC of clevis insert bolting (X-750) is occurring at Westinghouse designed plants, including Turkey Point Units 3 and 4. The Low failure consequence ranking would remain unchanged because clevis insert bolting presents only economic consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). As the clevis insert bolting has already been identified as having a high failure likelihood, there are no changes needed. The clevis insert bolting would remain in FMECA Group 2 during the 80-year period of operation.

The upper core plate alignment pins were placed in FMECA Group 1 for the 60-year period of operation with a Medium failure likelihood and Low failure consequence rankings. Wear is the only degradation mechanism that screened in during the 60-year period of operation. The estimated CUF for the upper core plate alignment pins is [ ], moderately above the 0.1 criteria for fatigue. Nonetheless, the inclusion of fatigue in the list of potential degradation mechanisms is not considered to impact the Medium failure likelihood ranking already in place. The low failure consequence ranking would also remain unchanged because failure of the upper core plate alignment pins presents neither economic nor safety consequence as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The upper core plate alignment pins would remain in FMECA Group 1 for the 80-year period of operation.

The upper support plate was placed in FMECA Group 0 for the 60-year period of operation and there are currently no failure likelihood or failure consequence rankings due to no degradation mechanisms screening in. The estimated CUF for the upper support plate is [ ], which is slightly above the threshold criteria for fatigue. This results in a Low failure likelihood ranking. Failure of the upper support plate is concluded to have economic but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). Therefore, the inclusion of fatigue as a potential degradation mechanism would likely result in either a Low or Medium failure consequence ranking per the logic of MRP-191. The combination of a Low failure likelihood and Low or Medium failure consequence for the 80-year period of operation, places the upper support plate in FMECA Group 1.

The upper core plate was placed in FMECA Group 2 for the 60-year period of operation with a Medium failure likelihood and Medium failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included wear, fatigue and IE. The increase in fluence during the 80-year period of operation caused the upper core plate to newly screen in for IASCC. Given the absence of any observed degradation of upper core plate to date, the overall failure likelihood is judged to remain Medium. The upper core plate presents both economic and safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4), and the original Medium failure consequence ranking is judged to remain unchanged. The upper core plate would remain in FMECA Group 2 for the 80-year period of operation.

The upper support column bases were placed in FMECA Group 1 for the 60-year period of operation with a Low failure likelihood and Medium failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included SCC, TE and IE. The increase from fluence Region 3 to Region [ ] during the 80-year period of operation caused upper support column bases to newly screen in for IASCC. Given the absence of any observed degradation of the upper support columns to date, the overall failure likelihood is judged to remain Low. The Medium failure consequences ranking would remain unchanged because failure of the upper support column bases presents economic but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The upper support column bases would remain in FMECA Group 1 for the 80-year period of operation.

The upper support column bolting was also placed in FMECA Group 1 for the 60-year period of operation with a Low failure likelihood and Medium failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included wear, fatigue and SR/IC. The increase in fluence from Region 3 to Region [ ] during the 80-year period of operation caused the upper support column bolting to newly screen in for IASCC and IE. Given the absence of any observed degradation of the upper support column bolting to date, the overall failure likelihood is judged to remain Low. The Medium failure consequence ranking would remain unchanged because failure of the upper support column bolting presents economic but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The upper support column bolting would remain in FMECA Group 1 for the 80-year period of operation.

The GTA lower flanges were placed in FMECA Group 1 for the 60-year period of operation with a Low failure likelihood and Medium failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included SCC and fatigue. The increase in fluence from Region 3 to Region [ ] during the 80-year period of operation caused the GTA lower flanges to newly screen in for IASCC and IE. Given the absence of any observed degradation of the GTA lower flanges to date, the overall failure likelihood is judged to remain Low. The Medium failure consequence ranking would remain unchanged because failure of the GTA lower flanges presents economic but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The GTA lower flanges would remain in FMECA Group 1 for the 80-year period of operation.

The GTA support pins (316 SS) were placed in FMECA Group 1 for the 60-year period of operation with a Low failure likelihood and Medium failure consequence rankings. Degradation mechanisms that screened in during the 60-year period of operation included wear, fatigue and SR/IC. The increase in fluence from Region 3 to Region [ ] during the 80-year period of operation caused the GTA support pins to newly screen in for IASCC and IE. Given the absence of any observed degradation of GTA support pins (316 SS) to date, the overall failure likelihood is judged to remain Low. The Medium failure consequence ranking would remain unchanged because failure of the GTA support pins presents economic but no safety consequences as indicated in Table 6-5 of MRP-191 (Reference C.4.4). The GTA support pins (316 SS) would remain in FMECA Group 1 for the 80-year period of operation.

C.2.5 Severity Categorization

The fifth step in the process was to use the results of the FMECA to categorize each of the components into one of the three following categories;

Category A: Component items for which aging degradation significance is minimal and/or aging effects are below the screening criteria.

Category B: Component items above screening levels but are not “lead” component items and aging degradation significance is moderate.

Category B’: Category B' items are defined as those “lead” component items that can be shown to be tolerant of the aging effects through a functionality assessment. This category was used for the original severity categorization of components, but will not be used for this gap analysis.

Category C: “Lead” component items for which aging degradation significance is high or moderate and aging effects are above screening levels.

This work was conducted by an expert panel for the 60-year period of operation. An expert panel was not assembled to conduct the severity categorization for the 60- to 80-year gap analysis; however, the 80-year FMECA rankings and severity categorization logic for the 60-year period of operation were utilized to evaluate the impact of the newly screened in degradation mechanisms for the 80-year period of operation.

For the components with no change in FMECA scores, including the five components newly screened in for fatigue and the five components newly screened in for fluence related degradation mechanisms, the categorization results for the 60-year period of operation were considered to remain unchanged for the 80-year period of operation. These newly screened in components due to fatigue and fluence are summarized in Section C.3.0.

The upper support plate FMECA ranking increased from 0 to 1, for the 80-year period of operation. The Low failure likelihood and the Low or Medium failure consequence would place the upper support plate in Category A using the logic employed by the expert panel for the 60-year period of operation.

The fuel alignment pins FMECA ranking increased from 1 to 2, for the 80-year period of operation. The High failure likelihood and Low failure consequence would place the fuel alignment pins in Category B using the logic employed by the expert panel for the 60-year period of operation.

In addition to changes in screening parameters and industry OE, PTN operating experience is reviewed to identify potential increases in degradation mechanism severity not captured through analytical methods. To date, no recordable indications were found as a result of the inspections performed under the reactor vessel internals program implemented for the initial license renewal period. Examinations of guide cards have shown wear which exceeds the allowable values, and additional inspections of 100 percent of guide cards are currently scheduled per the requirements of MRP-227-A. However, guide cards are currently identified as a lead component, and this additional operating experience does not impact the severity categorization. A detailed analysis of the plant operating experience is available in SLRA Section B.2.3.7.

As inspections of the reactor vessel internals continue to be performed, and the condition of reactor vessel internals components at PTN and throughout the industry are evaluated, the reactor vessel internals AMP will incorporate any indications of aging degradation severity that are inconsistent with the screening performed in this gap analysis. The review and assessment of relevant operating experience for its impacts on the program, including implementing procedures, are governed by NEI 03-08 and Appendix A of MRP-227-A. The reporting of inspection results and OE is treated as a “needed” category item under the implementation of NEI 03-08.

The severity categorization remains unchanged from the 60 year operating period.

C.2.6 Engineering Evaluation

The sixth step in the process was to perform an assessment of the reactor vessel internals components that would be most affected by the aging degradation mechanisms. The MRP-227-A engineering evaluation inspects each degradation mode in more detail and analyzes how they interact. The results of the MRP-227-A engineering evaluation were used to determine that there were a number of potential degradation modes in the Category B and Category C components that were of low failure probability and low failure consequence. The three basic types of engineering analysis were: (1) Irradiation Aging Analysis, (2) Extension of Irradiation Analysis to Other Components, and (3) Functionality of Remaining Components.

The MRP-227-A engineering evaluation is based on irradiation analysis for 60 years of operation. However, the irradiation analysis is not meant to be a bounding analysis, rather an indication of severity. Additionally, the fluence increase for the 60- to 80-year operating period represents an insignificant increase compared to the spread of fluence values among components. The MRP-227-A engineering evaluation from the 60 year operating period recognizes which components are expected to be the most significantly impacted and place them in the lead component category. After the additional fluence from the 60- to 80-year operating period, the previously identified lead components will remain the most severely impacted. Retaining the categorization of all lead components is appropriate and there are no components which have experienced an accelerated fluence accumulation, relative to other components, which would place them as new lead components.

C.2.7 Categorize for Inspection (Primary, Expansion, Existing, No Additional Measures) and Aging Management Strategy

The seventh step is to assign components into Primary, Expansion, Existing Programs, and No Additional Measures groups. These assignments are based on the results of all preceding efforts. While five additional components screened in for fatigue and five additional components screened in for fluence related degradation, this only impacted the FMECA score for one component (upper support plate), and did not impact the severity categorization for any components.

The industry OE concerning observed wear of the fuel alignment pins and the resulting increase in FMECA and severity rankings is considered significant enough to elevate the fuel alignment pins from No Additional Measures to Existing Programs Components. Visual (VT-3) inspections will be conducted under the ASME Section XI Program during the 80-year period of operation.

Both the clevis insert and baffle bolting, for which there has been industry OE, were categorized as Existing Programs Components for the 60-year period of operation. This categorization remains unchanged for the 80-year period of operation and the components will continue to be inspected under the Section XI Program.

The table in Attachment 2 outlines the new component categorization and aging management strategy. With the exception of the fuel alignment pins, the table is consistent with the component categorization and aging management strategy approved in Reference C.4.6. The details regarding the expansion links, examination method, and examination frequency are presented in Attachments 3,4, and 5 for Existing, Primary, and Expansion categories respectively.

C.2.8 Preparation of MRP-227-A Inspection and Evaluation Guidelines

The fuel alignment pins have been categorized from “No Additional Measures” to “Existing Programs.” Per the ASME Section XI program, the fuel alignment pins will be inspected using VT-3 inspections, once every Section XI interval. The remainder of the component inspection categorization has remained unchanged from the initial license renewal period, the I&E guidelines from MRP-227-A remain applicable, with minor changes for the subsequent period of operation.

The inspection schedule established for the initial license renewal can continue to use reactor vessel internals inspection intervals to sufficiently manage all identified degradation mechanisms. For components which required inspections to be performed based on a time period relative to the initial license renewal period, continuation of the ten-year interval cycle will be sufficient. The second ten-year inspection for the initial license renewal will be performed to the specifications of the subsequent license renewal inspections, establishing subsequent license renewal inspection requirements before entering the subsequent license renewal period. Inspection schedules will align with ISI interval and approved industry guidance.

For the internals hold down springs, spring height measurements must be extrapolated to 80 years of operation. Any examinations must be performed prior to entering the subsequent license renewal period.

The examination method and frequency for all applicable components is outlined in Attachments 3, 4, and 5.

C.3.0 CONCLUSIONS

The results of this gap analysis are summarized in table format in Attachment 1. Five additional components screen in for fatigue compared to the aging effects identified in the existing PTN reactor vessel internals program (Reference C.4.9). These components are listed as follows:

- Lower support columns
- Clevis insert
- Radial keys
- Upper core plate alignment pins
- Upper support plate

Five additional components screen in for IASCC compared to the aging effects identified in the existing PTN reactor vessel internals program (Reference C.4.9). These components are listed as follows:

- Upper core plate
- Upper support column bases
- Upper support column bolting
- GTA lower flanges
- GTA support pins

Three additional components screen in for IE compared to the aging effects identified in the existing PTN reactor vessel internals program (Reference C.4.9). These components are listed as follows:

- Upper support column bolting
- GTA lower flanges
- GTA support pins

Three additional components were recognized to have active degradation mechanisms within the industry. The failure likelihood of the fuel alignment pins was elevated to “High” to reflect this, resulting in a categorization increase from “No Additional Measures” to “Existing Programs”. The clevis insert bolting and baffle bolting had both previously been identified as a High failure likelihood and, as such, no changes were necessary.

In addition to aging mechanisms which are newly identified for components, many components may experience an increased degradation due to the additional operating period. Six of the eight degradation mechanisms managed by the reactor vessel internals program are influenced by time dependent parameters. The associated aging effects are expected to increase in severity for the 60-80 year operating period. Listed below are the components which are subject to aging effects that are expected to increase in severity.

Table C.3-1
Aging Effects with Potential for Increase in Severity by Component

COMPONENT	IASCC	Wear	Fatigue	IE	VS	SR/IC
Lower Core Plate	X	X	X	X	X	
Fuel Alignment Pins	X	X		X	X	
Lower Support Columns	X		X[a]	X	X	
Lower Support Column Bolting	X	X	X	X	X	X
Radial Keys		X	X[a]			
BMI Column Bodies	X		X	X	X	
BMI Bases and Extension Bars	X			X	X	
Clevis Insert		X	X[a]			
Upper Core Plate Alignment Pins		X	X[a]			
Internals Hold-Down Spring		X				
Clevis Insert Bolting		X				
Flux Thimble Tubes	X	X		X	X	
Core Barrel Flange		X				
Core Barrel Outlet Nozzles			X			
Lower Core Barrel	X			X		
Upper Core Barrel				X		
Thermal Shield				X		
Thermal Shield Flexures	X	X	X	X		X
Baffle-Former Assembly (input parameters provided are for baffle plates)	X			X	X	
Baffle-Former Bolts	X	X	X	X	X	X
Baffle Edge Bolts	X	X	X	X	X	X
Barrel-Former Bolts	X	X	X	X	X	X
Upper Support Plate			X[a]			
Upper Support Ring			X			

Table C.3-1
Aging Effects with Potential for Increase in Severity by Component (Continued)

COMPONENT	IASCC	Wear	Fatigue	IE	VS	SR/IC
Upper Core Plate		X	X	X		
Upper Support Column Bases				X		
Upper Support Column Bolting		X	X			X
GTA Lower Flanges			X			
Guide Cards		X	X			
GTA C-Tubes		X				
GTA Sheaths		X				
GTA Support Pins		X	X			X

Notes for Table C.3-1

a. While these components were not recognized in the initial license renewal AMP, the degradation mechanisms should have been screened in for the 40 to 60 year operating period.

The increase in severity is not significant enough to necessitate any changes in the program requirements. While five additional components screened in for fatigue and five additional components screened in for fluence related degradation mechanisms, this only impacted the FMECA score for the upper support plate, and did not impact the severity categorization for any components.

Based on the above changes, the results of MRP-227-A will be modified by categorizing the fuel alignment pins as an Existing Programs component. With this change, the results of MRP-227-A will be applicable for the subsequent period of extended operation. The component details, groupings, and inspection plans outlined in the attachments to this document reflect the conclusions of MRP-227-A, as modified by this gap analysis to be applicable for the SPEO. A detailed list of components and their respective inspection categories is available in Attachment 2. Attachments 3, 4, and 5 outline the components, inspection methodology, and frequency for the Existing Programs, Primary Components, and Expansion Components respectively. Attachment 6 details the relationships between Primary and Expansion components and outlines the acceptance criteria for each inspection.

C.4.0 REFERENCES

NRC (Generic Letters, NUREGs)

C.4.1 NUREG-2191, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, Final Report, July 2017

NEI

C.4.2 NEI 03-08, Rev. 2, Guideline for the Management of Materials Issues, January 2010

EPRI Reports

C.4.3 EPRI Technical Report No.1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)." Agencywide Documents Access and Management System (ADAMS) Accession No. ML12017A193 (Transmittal letter from the EPRI-MRP) and ADAMS Accession Nos. ML12017A194, ML12017A196, ML12017A197, ML12017A191, ML12017A192, ML12017A195 and ML12017A199 (Final Report), December 2011

C.4.4 EPRI Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design (MRP-191), Rev. 1, October 2016

C.4.5 EPRI Materials Reliability Program PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values (MRP-175), December 2005, ML061880278

Correspondence

C.4.6 Turkey Point Nuclear Generating Unit Nos. 3 and 4 – Staff Assessment of License Renewal Commitment for Reactor Vessel Internals Implementation Report and Inspection Plan (CAC Nos. MF1485 and MF1486), Adams Accession No. ML15336A046

C.4.7 License Amendment Request for Extended Power Uprate (LAR 205), Adams Accession No. ML103560169, October 21, 2010

Plant Documents and Other

C.4.8 WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Internals, ADAMS Accession No. ML011080790, March 2001

C.4.9 PTN-ENG-LRAM-00-0041, Rev. 8, Reactor Vessel Internals Aging Management Program License Renewal Basis Document

C.4.10 TB-14-5, Westinghouse Technical Bulletin, Reactor Internals Lower Radial Support Clevis Insert Cap Screw Degradation, August 25, 2014

C.4.11 TB-16-4, Westinghouse Technical Bulletin, Fuel Alignment Pin Malcomized Surface Degradation, August 15, 2016

								60-Year DM Screening												80-Year DM Screening											
COMPONENT	**MATERIAL**	**Effect Stress ≥ Threshold (30 ksi)**	**Structural Weld**	**Wear Potential**	**CUF ≥ 0.1**	**EPU CUF**	**Preload Req'd**	**60-Year Neutron Fluence Region**	**SCC**	**IASCC**	**Wear**	**Fatigue**	**TE**	**IE**	**VS**	**SR/IC**	**FMECA Group**	**CAT**	**CATEGORY**	**SLR Neutron Fluence Region**	**SCC**	**IASCC**	**Wear**	**Fatigue**	**TE**	**IE**	**VS**	**SR/IC**	**FMECA Group**	**CAT**	**CATEGORY**
Lower Core Plate	304 SS	Yes	Yes	Yes	Yes	[ ]	No	Region 5	Weld	IASCC	Wear	Fat		IE	VS		M,M,2	B	Existing Programs	[ ]	Weld	IASCC	Wear	Fat		IE	VS		M,M,2	B	Existing Programs
Fuel Alignment Pins	304 SS	Yes	No	Yes	No		No	Region 5		IASCC	Wear			IE	VS		L,L,1	A	No Additional Measures	[ ]		IASCC	Wear			IE	VS		H,L,2	B	Existing Program
Lower Support Forging	304 SS	No	No	No	No		No	Region 1									L,H,0	A	Expansion	[ ]									L,H,0	A	Expansion
Lower Support Columns	CF8 cast SS	No	No	No	No	[ ]	No	Region 5		IASCC			TE	IE	VS		M,L,1	B	Expansion	[ ]		IASCC		Fat	TE	IE	VS		M,L,1	B	Expansion
Lower Support Column Bolting	316 SS	Yes	No	No	Yes		Yes	Region 5		IASCC	Wear(I)	Fat		IE	VS	SR/IC	M,L,1	B	Expansion	[ ]		IASCC	Wear(I)	Fat		IE	VS	SR/IC	M,L,1	B	Expansion
Radial Keys	304 SS	No	Yes	Yes	No	[ ]	No	Region 1	Weld		Wear						L,L,1	A	No Additional Measures	[ ]	Weld		Wear	Fat					L,L,1	A	No Additional Measures
Diffuser Plate	304 SS	No	No	No	No		No	Region 1									0	A	No Additional Measures	[ ]									0	A	No Additional Measures
Secondary Core Support	304 SS	No	Yes	No	No		No	Region 1	Weld								L,L,1	A	No Additional Measures	[ ]	Weld								L,L,1	A	No Additional Measures
BMI Column Bodies	304 SS	Yes	Yes	No	Yes		No	Region 5	Weld	IASCC		Fat		IE	VS		M,L,1	B	Expansion	[ ]	Weld	IASCC		Fat		IE	VS		M,L,1	B	Expansion
BMI Bases (Cruciforms)	CF8 cast SS	No	No	No	No		No	Region 5		IASCC			TE	IE	VS		M,L,1	B	No Additional Measures	[ ]		IASCC			TE	IE	VS		M,L,1	B	No Additional Measures
BMI Extension Bars	304 SS	No	No	No	No		No	Region 5		IASCC				IE	VS		L,L,1	A	No Additional Measures	[ ]		IASCC				IE	VS		L,L,1	A	No Additional Measures
Head Cooling Spray Nozzles	304 SS	No	No	No	No		No	Region 1									0	A	No Additional Measures	[ ]									0	A	No Additional Measures
Clevis Insert	Alloy 600	No	No	Yes	No	[ ]	No	Region 1			Wear						L,L,1	A	No Additional Measures	[ ]			Wear	Fat					L,L,1	A	No Additional Measures
Upper Core Plate Alignment Pins	304 SS w/ Stellite hardfacing	No	Yes	Yes	No	[ ]	No	Region 3	Weld		Wear						M,L,1	B	Existing Programs	[ ]	Weld		Wear	Fat					M,L,1	B	Existing Programs
Internals Hold-Down Spring	304 SS	Yes	No	Yes	No		Yes	Region 1			Wear						L,L,1	B	Primary	[ ]			Wear						L,L,1	B	Primary
Head/Vessel Alignment Pins	304 SS	No	No	No	No		No	Region 1									0	A	No Additional Measures	[ ]									0	A	No Additional Measures
Clevis Insert Bolting	X-750	Yes	No	Yes	No		Yes	Region 1	SCC		Wear						H,L,2	B	Existing Programs	[ ]	SCC		Wear						H,L,2	B	Existing Programs
Flux Thimble Tubes	316 SS	No	Yes	Yes	No		No	Region 5	Weld	IASCC	Wear			IE	VS		H,L,2	C	Existing Programs	[ ]	Weld	IASCC	Wear			IE	VS		H,L,2	C	Existing Programs
Core Barrel Flange	304 SS	No	Yes	Yes	No	[ ]	No	Region 1									L,H,2	B	Existing Programs	[ ]									L,H,2	B	Existing Programs
									Weld		Wear						M,H,3	C	Primary		Weld		Wear						M,H,3	C	Primary
Core Barrel Outlet Nozzles	304 SS	Yes	Yes	No	Yes	[ ]	No	Region 1	Weld			Fat					M,M,2	B	Expansion	[ ]	Weld			Fat					M,M,2	B	Expansion
Lower Core Barrel	304 SS	Yes	Yes	No	No		No	Region 4	Weld	IASCC				IE			M,H,3	C	Primary	[ ]	Weld	IASCC				IE			M,H,3	C	Primary
Upper Core Barrel	304 SS	Yes	Yes	No	No		No	Region 3	Weld					IE			M,H,3	C	Primary	[ ]	Weld					IE			M,H,3	C	Primary
Thermal Shield	304 SS	No	No	No	No		No	Region 4						IE			L,L,1	A	No Additional Measures	[ ]						IE			L,L,1	A	No Additional Measures
Thermal Shield Flexures	316 SS	Yes	No	No	Yes		Yes	Region 4		IASCC	Wear(I)	Fat		IE		SR/IC	M,L,1	B	Primary	[ ]		IASCC	Wear(I)	Fat		IE		SR/IC	M,L,1	B	Primary
Baffle and Former Assembly (Input parameters provided are for baffle plates.)	304 SS	No	No	No	No		No	Region 6		IASCC				IE	VS		M,L,1	B	Primary	[ ]		IASCC				IE	VS		M,L,1	B	Primary

								60-Year DM Screening												80-Year DM Screening											
COMPONENT	**MATERIAL**	**Effect Stress ≥ Threshold (30 ksi)**	**Structural Weld**	**Wear Potential**	**CUF ≥ 0.1**	**EPU CUF**	**Preload Req'd**	**60-Year Neutron Fluence Region**	**SCC**	**IASCC**	**Wear**	**Fatigue**	**TE**	**IE**	**VS**	**SR/IC**	**FMECA Group**	**CAT**	**CATEGORY**	**SLR Neutron Fluence Region**	**SCC**	**IASCC**	**Wear**	**Fatigue**	**TE**	**IE**	**VS**	**SR/IC**	**FMECA Group**	**CAT**	**CATEGORY**
Baffle-Former Bolts	347 SS	Yes	No	No	Yes		Yes	Region 6		IASCC	Wear(I)	Fat		IE	VS	SR/IC	H,M,3	C	Primary	[ ]		IASCC	Wear(I)	Fat		IE	VS	SR/IC	H,M,3	C	Primary
Baffle Edge Bolts	316 SS	Yes	No	No	Yes		Yes	Region 6		IASCC	Wear(I)	Fat		IE	VS	SR/IC	H,M,3	C	Primary	[ ]		IASCC	Wear(I)	Fat		IE	VS	SR/IC	H,M,3	C	Primary
Barrel-Former Bolts	316 SS	Yes	No	No	Yes		Yes	Region 6		IASCC	Wear(I)	Fat		IE	VS	SR/IC	H,L,2	C	Expansion	[ ]		IASCC	Wear(I)	Fat		IE	VS	SR/IC	H,L,2	C	Expansion
Upper Support Plate	304 SS	No	No	No	No	[ ]	No	Region 1									0	A	No Additional Measures	[ ]				Fat					M,L,1	A	No Additional Measures
Upper Support Ring	304 SS	Yes	Yes	No	Yes		No	Region 1	Weld			Fat					M,M,2	B	Existing Programs	[ ]	Weld			Fat					M,M,2	B	Existing Programs
Upper Core Plate	304 SS	Yes	No	Yes	Yes	[ ]	No	Region 4			Wear	Fat		IE			M,M,2	B	Expansion	[ ]		IASCC	Wear	Fat		IE			M,M,2	B	Expansion
Upper Support Column Bases	CF8 cast SS	Yes	No	No	No		No	Region 3	SCC				TE	IE			L,M,1	A	No Additional Measures	[ ]	SCC	IASCC			TE	IE			L,M,1	A	No Additional Measures
Upper Support Columns	304 SS	Yes	No	No	No	[ ]	No	Region 3									0	A	No Additional Measures	[ ]									0	A	No Additional Measures
Upper Support Column Bolting	316 SS	Yes	No	No	No		Yes	Region 3			Wear(I)	Fat(I)				SR/IC	L,M,1	A	No Additional Measures	[ ]		IASCC	Wear(I)	Fat(I)		IE		SR/IC	L,M,1	A	No Additional Measures
Upper Instrumentation Column	304 SS	No	No	No	No		No	Region 1									0	A	No Additional Measures	[ ]									0	A	No Additional Measures
GTA Lower Flanges	304 SS	Yes	Yes	No	Yes		No	Region 3	Weld			Fat					L,M,1	A	Primary	[ ]	Weld	IASCC		Fat		IE			L,M,1	A	Primary
Guide Cards	304 SS	Yes	Yes	Yes	Yes		No	Region 1	Weld		Wear	Fat					H,M,3	C	Primary	[ ]	Weld		Wear	Fat					H,M,3	C	Primary
GTA C-Tubes	304 SS	No	No	Yes	No		No	Region 3			Wear						M,M,2	C	No Additional Measures	[ ]			Wear						M,M,2	C	No Additional Measures
GTA Sheaths	304 SS	No	No	Yes	No		No	Region 3			Wear						M,M,2	C	No Additional Measures	[ ]			Wear						M,M,2	C	No Additional Measures
GTA Support Pins	316 SS	Yes	No	Yes	Yes		Yes	Region 3			Wear	Fat				SR/IC	L,M,1	A	Existing Programs	[ ]		IASCC	Wear	Fat		IE		SR/IC	L,M,1	A	Existing Programs
GTA Bolting	316 SS	No	No	No	No		Yes	Region 1									0	A	No Additional Measures	[ ]									0	A	No Additional Measures

Notes:

(I) indicates that the degradation method screens in due to interactions with irradiation induced degradation mechanisms, i.e., Wear(I) appears when wear only screens in due to interactions with irradiation stress relaxation or void swelling. It is not included if the component screens in for the degradation mechanism due to other screening parameters as well.

Color coding is used to identify areas of interest in this table. Blue is used where changes related to fatigue are incorporated or considered. Yellow and green are used to identify where changes related to cumulative fluence are incorporated or considered; with yellow identifying an increase in fluence and green identifying a decrease in fluence. Red is used to identify the change in the fuel alignment pins category.

FMECA Group descriptions are ordered as Failure Likelihood, Failure Consequence, FMECA Group.

The column "CAT" is the severity category.

COMPONENT	MATERIAL	INTENDED FUNCTION	CATEGORY
Lower Internals Assembly			
Lower Core Plate	304 SS	Core Support, Flow Distribution, Guide Instrumentation	Existing Programs
Fuel Alignment Pins	304 SS	Core Support, Flow Distribution, Guide Instrumentation	Existing Programs
Lower Support Forging	304 SS	Core Support, Flow Distribution, Guide Instrumentation	Expansion
Lower Support Columns	CF8 cast SS	Core Support, Guide Instrumentation	Expansion
Lower Support Column Bolting	316 SS	Core Support, Guide Instrumentation	Expansion
Radial Keys	304 SS	Core Support	No Additional Measures
Diffuser Plate	304 SS	Flow Distribution	No Additional Measures
Secondary Core Support	304 SS	Core Support, Flow Distribution, Guide Instrumentation	No Additional Measures
Bottom-Mounted Instrument Column Bodies	304 SS	Guide Instrumentation	Expansion
Bottom-Mounted Instrumentation Bases and Extension Bars	CF8 cast SS/304 SS	Guide Instrumentation	No Additional Measures
Head Cooling Spray Nozzles	304 SS	Flow Distribution	No Additional Measures
Interfacing Components			
Clevis Insert	Alloy 600	Core Support	No Additional Measures
Upper Core Plate Alignment Pins	304 SS w/Stellite hardfacing	Core Support, Flow Distribution	Existing Programs
Internals Hold-Down Spring	304 SS	Core Support	Primary
Head/Vessel Alignment Pins	304 SS	Guide RCCAs	No Additional Measures
Clevis Insert Bolting	X-750	Core Support	Existing Programs
Flux Thimble Tubes	316 SS	Guide Instrumentation	Existing Programs

COMPONENT	MATERIAL	INTENDED FUNCTION	CATEGORY
Lower Internals Assembly/Core Barrel Subassembly			
Core Barrel Flange	304 SS	Core Support, Flow Distribution	Existing Programs
			Primary
Core Barrel Outlet Nozzles	304 SS	Core Support, Flow Distribution	Expansion
Lower Core Barrel	304 SS	Core Support, Flow Distribution, Shield Vessel	Primary
Upper Core Barrel	304 SS	Core Support, Flow Distribution, Shield Vessel	Primary
Thermal Shield	304 SS	Shield Vessel	No Additional Measures
Thermal Shield Flexures	316 SS	Shield Vessel	Primary
Lower Internals Assembly/Baffle-Former Subassembly			
Baffle and Former Assembly	304 SS	Core Support, Flow Distribution, Shield Vessel	Primary
Baffle-Former Bolts	347 SS	Core Support, Flow Distribution, Shield Vessel	Primary
Baffle Edge Bolts	316 SS	Core Support, Flow Distribution, Shield Vessel	Primary
Barrel-Former Bolts	316 SS	Core Support, Flow Distribution, Shield Vessel	Expansion
Upper Internals Assembly			
Upper Support Plate	304 SS	Core Support, Guide RCCAs	No Additional Measures
Upper Support Ring	304 SS	Core Support, Guide RCCAs	Existing Programs
Upper Core Plate	304 SS	Core Support, Flow Distribution	Expansion
Upper Support Column Bases	CF8 cast SS	Core Support, Guide RCCAs, Guide Instrumentation	No Additional Measures
Upper Support Columns	304 SS	Core Support, Guide RCCAs, Guide Instrumentation	No Additional Measures
Upper Support Column Bolting	316 SS	Core Support, Guide and Support RCCAs	No Additional Measures
Upper Instrumentation Column (Thermocouple Support Tubes)	304 SS	Guide Instrumentation	No Additional Measures

COMPONENT	MATERIAL	INTENDED FUNCTION	CATEGORY
Guide Tube Assemblies (GTA)			
GTA Lower Flanges	304 SS	Guide RCCAs	Primary
Guide Cards	304 SS	Guide RCCAs	Primary
GTA C-Tubes	304 SS	Guide RCCAs	No Additional Measures
GTA Sheaths	304 SS	Guide RCCAs	No Additional Measures
GTA Support Pins	316 SS	Guide RCCAs	Existing Programs (Note 1)
GTA Bolting	316 SS	Guide RCCAs	No Additional Measures

1. There is no formal program document for the GTA Support Pin replacement program, however, appropriate actions will be taken upon receiving any further recommendations from Westinghouse. Per RAI-2 response in Reference C.4.9, GTA support pins are managed through multiple approaches. While the support pins are not a part of the ASME Section XI B-N-3 inspections, the VT-3 inspection of the upper core plate will provide a partial view of the support pins. These inspections provide a partial view of the split pin heads associated with the peripheral guide tube assemblies from the top of the upper core plate, and the split pin leaves associated with all guide tube assemblies from the bottom of the upper core plate. Additionally, a foreign object search and retrieval (FOSAR) of the reactor vessel is performed every fuel outage and a visual inspection of the steam generator primary channels is performed during outages when eddy current testing of the steam generator tubes is performed. These inspections should detect the presence of split pin fragments in the unlikely event that failure does occur.

Component	Applicability	Effect (Mechanism)	Reference Document	Generic Requirement Description	Examination Method and Frequency
Core Barrel Assembly Core barrel flange	PTN 3 PTN 4	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination to determine general condition for excessive wear	All accessible surfaces; one time per interval
Upper Internals Assembly Upper support ring or skirt	PTN 3 PTN 4	Cracking (SCC, Fatigue)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces; one time per interval
Lower Internals Assembly Lower core plate	PTN 3 PTN 4	Cracking (IASCC, fatigue) Aging Management (IE)	ASME Code Section XI	Visual (VT-3) examination of the lower core plate to detect evidence of distortion and/or loss of bolt integrity	All accessible surfaces; one time per interval
Lower Internals Assembly Lower core plate	PTN 3 PTN 4	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces; one time per interval
Lower Internals Assembly Fuel alignment pins	PTN 3 PTN 4	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces; one time per interval
Bottom-Mounted Instrumentation System Flux thimble tubes	PTN 3 PTN 4	Loss of material (wear)	BMI-FTT-IP	Surface (ET) examination	ET surface examination of full length tubes at frequency specified in BMI-FTT-IP. Tube selection and frequency based upon engineering evaluation of previous examination results.
Alignment and Interfacing Components Clevis insert bolt	PTN 3 PTN 4	Loss of material (wear) (Note 1)	ASME Code Section XI	Visual (VT-3) examination (Note 2)	All accessible surfaces; one time per interval

Component	Applicability	Effect (Mechanism)	Reference Document	Generic Requirement Description	Examination Method and Frequency
Alignment and Interfacing Components Upper core plate alignment pins	PTN 3 PTN 4	Loss of material (wear) Cracking (fatigue)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces; one time per interval
Guide Tube Assemblies (GTA) GTA Support Pins	PTN 3 PTN 4	Loss of material (wear) Cracking (IASCC, fatigue) Aging Management (IE)	Multiple (Note 3)	Visual (VT-3) examination, FOSAR	Partial view, as a part of the upper core plate inspection.

1. Bolt was screened in because of stress relaxation and associated cracking; however, wear of the clevis/insert is the issue.
2. Based on Reference C.4.10, if a VT-3 inspection is performed, it is recommended to look for aggressive or abnormal wear at the radial key/ clevis insert interfacing surfaces as compared to the previous inspection, if available. The radial key does not make contact with the full length of the clevis insert: if wear is significant it would be visible as a step located toward the bottom end of the clevis insert. Look for signs of looseness or dislocation at the interface between the clevis insert and vessel lug. Faces of the insert and vessel lug are generally flush: dislocations may be visible by the insert protruding toward the vessel centerline as compared to the vessel lug. Look for wear between the bolt head and lock bar and/or bolt head dislocation. Look for broken tack welds and dislocation of the dowel pin. This is not applicable if a VT-1 inspection is performed.
3. There is no formal program document for the GTA Support Pin replacement program, however, appropriate actions will be taken upon receiving any further recommendations from Westinghouse. Per RAI-2 response in Reference C.4.9, GTA support pins are managed through multiple approaches. While the support pins are not a part of the ASME Section XI B-N-3 inspections, the VT-3 inspection of the upper core plate will provide a partial view of the support pins. These inspections provide a partial view of the split pin heads associated with the peripheral guide tube assemblies from the top of the upper core plate, and the split pin leaves associated with all guide tube assemblies from the bottom of the upper core plate. Additionally, a foreign object search and retrieval (FOSAR) of the reactor vessel is performed every fuel outage and a visual inspection of the steam generator primary channels is performed during outages when eddy current testing of the steam generator tubes is performed. These inspections should detect the presence of split pin fragments in the unlikely event that failure does occur.

Component	Applicability	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method/Frequency	Examination Coverage
Control Rod Guide Tube Assembly (CRGT) Guide plates (cards)	PTN 3 PTN 4 (Note 7)	Loss of material (wear)	None	Visual (VT-3) examinations are required on a ten-year interval beginning with what would have been the second ten year interval inspection from the initial license renewal. (Note 7)	20% examination of the number of CRGT assemblies, with all guide cards within each selected CRGT assembly examined. (Note 7)
Control Rod Guide Tube Assembly Lower flange welds	PTN 3 PTN 4	Cracking (SCC, IASCC, fatigue) Aging Management (IE and TE)	Bottom-mounted instrumentation (BMI) column bodies, lower support column bodies (cast), upper core plate, lower support casting/ forging	Enhanced visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds are required on a ten-year interval beginning with what would have been the second ten year interval inspection from the initial license renewal.	100% of outer (accessible) CRGT lower flange weld surfaces and adjacent base metal on the adjacent base metal on the individual periphery CRGT assemblies. (Note 2)
Core Barrel Assembly Upper core barrel flange weld	PTN 3 PTN 4	Cracking (SCC)	Lower support column bodies (non cast) core barrel outlet nozzle welds	Periodic enhanced visual (EVT-1) examinations are required on a ten-year interval beginning with what would have been the second ten year interval inspection from the initial license renewal.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal (Note 4)
Core Barrel Assembly Upper and lower core barrel cylinder girth welds	PTN 3 PTN 4	Cracking (SCC, IASCC, Fatigue)	Upper and lower cylinder axial welds Lower support column bodies (only applies to the lower core barrel cylinder girth welds)	Periodic enhanced visual (EVT-1) examinations are required on a ten-year interval beginning with what would have been the second ten year interval inspection from the initial license renewal.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal (Note 4)

Component	Applicability	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method/Frequency	Examination Coverage
Core Barrel Assembly Lower core barrel flange weld (Note 5)	PTN 3 PTN 4	Cracking (SCC, Fatigue)	None	Periodic enhanced visual (EVT-1) examinations are required on a ten-year interval beginning with what would have been the second ten year interval inspection from the initial license renewal.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal (Note 4)
Baffle-Former Assembly Baffle-edge bolts	PTN 3 PTN 4	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads Aging Management (IE and SR/IC) (Note 6)	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.	Bolts and locking devices on high fluence seams. 100% of components accessible from core side. (Note 3)
Baffle-Former Assembly Baffle-former bolts	PTN 3 PTN 4	Cracking (IASCC, Fatigue) Aging Management (IE and SR/IC) (Note 6)	Lower support column bolts, barrel-former bolts	Baseline volumetric (UT) examination between 25 and 35 EFPY, with subsequent examinations on a chronological ten-year interval.	100% of accessible bolts (Note 3). Heads accessible from the core side. UT accessibility may be affected by complexity of head and locking device designs.

Component	Applicability	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method/Frequency	Examination Coverage
Baffle-Former Assembly Includes: Baffle plates, baffle edge bolts and indirect effects of void swelling in former plates	PTN 3 PTN 4	Distortion (void swelling) or cracking (IASCC) that results in • Abnormal interaction with fuel assemblies • Gaps along high fluence baffle joint • Vertical displacement of baffle plates near high fluence joint • Broken or damaged edge bolt locking systems along high fluence baffle joint	None	Visual (VT-3) examination to check for evidence of distortion, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.	Core side surface as indicated
Alignment and Interfacing Components Internals hold down spring	PTN 3 PTN 4	Distortion (loss of load) Note: This mechanism was not strictly identified in the original list of age-related degradation mechanisms.	None	Direct measurement of spring height within three cycles of the beginning of the subsequent license renewal period. If the first set of measurements is not sufficient to determine life, spring height measurements must be taken during the next two outages, in order to extrapolate the expected spring height to 80 years.	Measurements should be taken at several points around the circumference of the spring, with a statistically adequate number of measurements at each point to eliminate uncertainty.
Thermal Shield Assembly Thermal Shield Flexures	PTN 3 PTN 4	Cracking (Fatigue) Loss of material (wear) that results in thermal shield flexures excessive wear, fracture, or complete separation.	None	Visual (VT-3) examinations are required on a ten-year interval beginning with what would have been the second ten year interval inspection from the initial license renewal.	100% of thermal shield flexures.

Notes:

1. Examination acceptance criteria and expansion criteria for the Westinghouse components are in Attachment 6.
2. A minimum of 75% of the total identified sample population must be examined.
3. A minimum of 75% of the total population (examined + unexamined), including coverage consistent with the Expansion criteria in Attachment 6, must be examined for inspection credit.
4. A minimum of 75% of the total weld length (examined + unexamined), including coverage consistent with the Expansion criteria in Attachment 6, must be examined from either the inner or outer diameter for inspection credit.
5. The lower core barrel flange weld may be alternatively designated as the core barrel-to-support plate weld in some Westinghouse plant designs.
6. Void swelling effects on this component is managed through management of void swelling on the entire baffle-former assembly.
7. Unit 4 inspection frequency changed by corrective action to approximately 9 years based on 8.8 EFPY accumulated and from 20% to 100% examination of the number of CRGT assemblies based on the inspections performed spring 2016 in accordance with WCAP-17451-P (AR 02124311). After the expanded inspection coverage is complete, the inspection frequency and examination coverage will revert to the 10 year interval and 20% inspection coverage, barring further corrective actions. This does not apply to Unit 3.

Component	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Upper Internals Assembly Upper core plate	PTN 3 PTN 4	Cracking (IASCC, Fatigue, Wear) Aging Management (IE) (Note 3)	Control rod guide tube (CRGT) lower flange weld	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of accessible surfaces (Note 2)
Lower Internals Assembly Lower support forging or castings	PTN 3 PTN 4 (both units have forgings)	Cracking (IASCC, Fatigue) Aging Management (TE in casting)	CRGT lower flange weld	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of accessible surfaces (Note 2)
Core Barrel Assembly Barrel-former bolts	PTN 3 PTN 4	Cracking (IASCC, Fatigue) Aging Management (IE, Void Swelling and SR/IC)	Baffle-former bolts	Volumetric (UT) examination. Re-inspection every 10 years following initial inspection.	100% of accessible bolts. Accessibility may be limited by presence of thermal shields or neutron pads. (Note 2)
Lower Support Assembly Lower support column bolts	PTN 3 PTN 4	Cracking (IASCC, Fatigue) Aging Management (IE and SR/IC)	Baffle-former bolts	Volumetric (UT) examination. Re-inspection every 10 years following initial inspection.	100% of accessible bolts or as supported by plant specific justification. (Note 2)
Core Barrel Assembly Core barrel outlet nozzle welds	PTN 3 PTN 4	Cracking (SCC, fatigue) Aging Management (IE of lower sections)	Upper core barrel flange weld	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal. (Note 2)
Core Barrel Assembly Upper and lower core barrel cylinder axial welds	PTN 3 PTN 4	Cracking (SCC, IASCC) Aging Management (IE)	Upper and lower core barrel cylinder girth welds	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal. (Note 2)

Component	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Lower Support Assembly Lower support column bodies (non cast)	NA to PTN 3 NA to PTN 4	Cracking (IASCC) Aging Management (IE)	Upper core barrel flange weld	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of accessible surfaces (Note 2)
Lower Support Assembly Lower support column bodies (cast)	PTN 3 PTN 4	Cracking (IASCC) including the detection of fractured support columns Aging Management (IE)	Lower core barrel cylinder girth weld (IE, IASCC) CRGT lower flanges	Enhanced Visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of accessible support columns (Note 2)
Bottom-Mounted Instrumentation System Bottom-mounted instrumentation (BMI) column bodies	PTN 3 PTN 4	Cracking (Fatigue) including the detection of completely fractured column bodies. Aging Management (IE)	CRGT lower flanges	Visual (VT-3) examination of BMI column bodies as indicated by difficulty of insertion/withdrawal of flux thimbles. Re-inspection every 10 years following initial inspection. Flux thimble insertion/withdrawal to be monitored at each inspection interval.	100% of BMI column bodies for which difficulty is detected during flux thimble insertion/withdrawal.

Notes

1. Examination acceptance criteria and expansion criteria for the Westinghouse components are in Attachment 6.
2. A minimum of 75% coverage of the entire examination area or volume, or a minimum sample size of 75% of the total population of like components of the examination is required (including both the accessible and inaccessible portions).
3. IE must be considered in a flaw evaluation for the upper core plate. Included due to fluence change resulting from extended power uprate (EPU) implemented in 2012 (Unit 3) and 2013 (Unit 4).

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Control Rod Guide Tube Assembly Guide plates (cards)	Turkey Point 3 Turkey Point 4	Visual (VT-3) examination. The specific relevant condition is wear that could lead to loss of control rod alignment and impede control assembly insertion.	None	N/A	N/A
Control Rod Guide Tube Assembly Lower flange welds	Turkey Point 3 Turkey Point 4	Enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	a. Bottom-mounted instrumentation (BMI) column bodies b. Lower support column bodies (cast), and upper core plate and lower support forging or casting	a. Confirmation of surface-breaking indications in two or more control rod guide tube (CRGT) lower flange welds, combined with flux thimble insertion/withdrawal difficulty, shall require visual (VT-3) examination of BMI column bodies by the completion of the next refueling outage. b. Confirmation of surface-breaking indications in two or more CRGT lower flange welds shall require EVT-1 examination of cast lower support column bodies, upper core plate and lower support forgings/castings within three fuel cycles following the initial observation.	a. For BMI column bodies, the specific relevant condition for the VT-3 examination is completely fractured column bodies. b. For cast lower support column bodies, upper core plate and lower support forgings/ castings, the specific relevant condition is a detectable crack-like surface indication.

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Core Barrel Assembly Upper core barrel flange weld	Turkey Point 3 Turkey Point 4	Periodic enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	a. Core barrel outlet nozzle welds b. Lower support column bodies (non cast)	a. The confirmed detection and sizing of a surface-breaking indication with a length greater than two inches in the upper core barrel flange weld shall require that the EVT-1 examination be expanded to include the core barrel outlet nozzle welds by the completion of the next refueling outage. b. If extensive cracking in the remaining core barrel outlet nozzle welds is detected, EVT-1 examination shall be expanded to include the upper six inches of the accessible surfaces of the non-cast lower support column bodies within three fuel cycles following the initial observation.	a and b. The specific relevant condition for the expansion core barrel outlet nozzle weld and lower support column body examination is a detectable crack-like surface indication.
Core Barrel Assembly Lower core barrel flange weld (Note 2)	Turkey Point 3 Turkey Point 4	Periodic enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	None	None	None

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Core Barrel Assembly Upper core barrel cylinder girth welds	Turkey Point 3 Turkey Point 4	Periodic enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	Upper core barrel cylinder axial welds	The confirmed detection and sizing of a surface-breaking indication with a length greater than two inches in the upper core barrel cylinder girth welds shall require that the EVT-1 examination be expanded to include the upper core barrel cylinder axial welds by the completion of the next refueling outage.	The specific relevant condition for the expansion upper core barrel cylinder axial weld examination is a detectable crack-like surface indication.
Core Barrel Assembly Lower core barrel cylinder girth welds	Turkey Point 3 Turkey Point 4	Periodic enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	a. Lower core barrel cylinder axial welds b. Lower support column bodies (cast)	The confirmed detection and sizing of a surface-breaking indication with a length greater than two inches in the lower core barrel cylinder girth welds shall require that the EVT-1 examination be expanded to include the lower core barrel cylinder axial welds by the completion of the next refueling outage and the lower support column bodies (cast) within the next three refueling outages.	The specific relevant condition for the expansion lower core barrel cylinder axial weld examination is a detectable crack-like surface indication.
Baffle-Former Assembly Baffle-edge bolts	Turkey Point 3 Turkey Point 4	Visual (VT-3) examination. The specific relevant conditions are missing or broken locking devices, failed or missing bolts, and protrusion of bolt heads.	None	N/A	N/A

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Baffle-Former Assembly Baffle-former bolts	Turkey Point 3 Turkey Point 4	Volumetric (UT) examination. The examination acceptance criteria for the UT of the baffle-former bolts shall be established as part of the examination technical justification.	Lower support column bolts Barrel-former bolts	a. Confirmation that more than 5% of the baffle-former bolts actually examined on the four baffle plates at the largest distance from the core (presumed to be the lowest dose locations) contain unacceptable indications shall require UT examination of the lower support column bolts within the next three fuel cycles. b. Confirmation that more than 5% of the lower support column bolts actually examined contain unacceptable indications shall require UT examination of the barrel-former bolts.	a and b. The examination acceptance criteria for the UT of the lower support column bolts and the barrel-former bolts shall be established as part of the examination technical justification.
Baffle-Former Assembly Assembly	Turkey Point 3 Turkey Point 4	Visual (VT-3) examination. The specific relevant conditions are evidence of abnormal interaction with fuel assemblies, gaps along high fluence shroud plate joints, vertical displacement of shroud plates near high fluence joints, and broken or damaged edge bolt locking systems along high fluence baffle plate joints.	None	N/A	N/A

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Alignment and Interfacing Components Internals hold down spring	Turkey Point 3 Turkey Point 4	Direct physical measurement of spring height. The examination acceptance criterion for this measurement is that the remaining compressible height of the spring shall provide hold-down forces within the plant-specific design tolerance.	None	N/A	N/A
Thermal Shield Assembly Thermal shield flexures	Turkey Point 3 Turkey Point 4	Visual (VT-3) examination. The specific relevant conditions for thermal shield flexures are excessive wear, fracture, or complete separation.	None	N/A	N/A

Notes:

1. The examination acceptance criterion for visual examination is the absence of the specified relevant condition(s).
2. The lower core barrel flange weld may alternatively be designated as the core barrel-to-support plate weld in some Westinghouse plant designs.

Appendix D

Technical Specification Changes

The Code of Federal Regulations, Title 10 at 54.22, requires applicants to include any Technical Specification changes, or additions, necessary to manage the effects of aging during the subsequent period of extended operation as part of the renewal application. Based on a review of the information provided in the Turkey Point Subsequent License Renewal Application and Technical Specifications, no Technical Specifications changes are being submitted with this Application.