APPLICATION FOR RENEWED OPERATING LICENSES

POINT BEACH NUCLEAR PLANT UNITS 1 & 2

TECHNICAL AND ADMINISTRATIVE INFORMATION

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1.0 ADMINISTRATIVE INFORMATION

This application has been prepared to provide the administrative, technical and environmental information required by 10 CFR 54 (Reference 1) and 10 CFR 51 (Reference 2) to support the renewal of the operating licenses for Point Beach Nuclear Plant Units 1 and 2.

Consistent with the expectations in RIS 2001-05 (Reference 3), one hardcopy of this application is being provided for the public document room, with remaining copies on CD-ROM. Another three hard copies are being provided to the NRC License Renewal Project Manager. Specially formatted CDs are provided for ADAMS and Internet Web page use. For the reviewer's convenience, CD-ROMs are provided which contain a copy of the Final Safety Analysis Report (FSAR) and the license renewal (LR) drawings prepared in support of the license renewal effort. Hyperlinks to those documents are provided in the application where appropriate. Four sets of hardcopy drawings are also being provided to the NRC under a separate cover letter.

The FSAR, LR drawings, and other references cited within the application are for information only, and are not incorporated by reference in this application. The LR drawings provided with this application are not intended to be kept up to date for the life of the plant. A license renewal flag for each component will be maintained in CHAMPS as part of the equipment qualification information data base.

This section of the application provides the following information:

1. Information on the organization of the application (Section 1.1).
2. A general plant description (Section 1.2).
3. The administrative information required by 10 CFR 54.17 and 10 CFR 54.19 (Section 1.3).
4. Summary of abbreviations and passive function code definitions (Section 1.5).
5. A distribution list for written communications related to the application (Section 1.6).

1.1 Application Format and Content

The following discussion describes the content of the Point Beach Nuclear Plant (sometimes called “PBNP”) License Renewal Application. In general the overall outline of the Application is constructed as described in NEI 95-10, Rev. 4 draft. The construction of the table structure however follows a format arrived at during discussions between the NRC License Renewal review staff and the nuclear power industry during 2002 and 2003.

Section 1.0 provides the administrative information required by Part 54 of Title 10 of the Code of Federal Regulations, Sections 17 and 19 (10 CFR 54.17 and 10 CFR 54.19).

Section 2.0 provides the scoping and screening methodology. Section 2 also describes and justifies the methodology used to determine the systems, structures, and components within the scope of license renewal and the structures and components subject to an aging management review (AMR). The system groupings in Sections 2 and 3 are organized to be consistent with NUREG-1800 (Reference 5). Table 2.2-1, Plant Level Scoping Results, provides listings of the plant mechanical systems, structures, and electrical/instrumentation and controls (I&C) systems, and identifies those plant systems and structures that are and are not within the scope of license renewal. Section 2.3, Section 2.4 and Section 2.5 provide a description of systems, their intended functions, and for information only, cross references to FSAR sections and LR drawings. Each system subsection has a table listing component groups subject to an AMR, their passive intended function. The drawings and FSAR are provided as a separate attachment for use as review tools.

Section 3.0 describes the results of the AMRs for the components and structures requiring AMRs. Section 3 identifies the components and structures subject to AMR including a comparison to the structures and components identified in the NRC’s “Generic Aging Lessons Learned (GALL) Report,” NUREG-1801, (Reference 6) which are combined into Standard Review Plan System groups. Those PBNP component groups with aging effects, and aging management programs selected to manage those effects which are consistent with the assumptions made in NUREG-1801, are contained in a set of tables that are identical to those in NUREG-1801, Volume I and the NUREG-1800, Standard Review Plan. A second set of tables in each Section 3 system grouping provides aging management information including component type, intended function, material, environment, aging effect requiring management and selected aging management programs for each component type. These system specific tables also include columns with references to NUREG -1801, Volume 2, line items and associated NUREG-1801 Volume 1 line items (duplicated in Table 3.x.1 of each SRP system group). Finally the last column of each table in Section 3 is set aside for notes or additional explanatory information specific to that line item. In addition these tables have hyperlinked cross references to the aging management details in Appendix B. A more detailed description of this table construction and interrelationship is provided in Section 3.

Section 4.0 includes a list of time-limited aging analyses (TLAAs), as defined by 10 CFR 54.3. It includes the identification of the component or subject, and an explanation of the time dependent aspects of the calculation or analysis. Section 4 demonstrates that the analyses remain valid for the period of extended operation, the analyses have been projected to the end of the period of extended operation, or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. Section 4 also states that three 10 CFR 50.12 exemptions involving a time-limited aging analysis as defined in 10 CFR 54.3 are required during the period of extended operation. There are some issues discussed in Section 4 that are not considered TLAAs. These are included to provide information on some issues that have been routinely discussed as part of Section 4 in past license renewal applications.

Appendix A1.0, Final Safety Analysis Report (FSAR) Supplements, contains a summary description of the programs for managing the effects of aging for the period of extended operation. A summary description of the evaluation of time-limited aging analyses for the period of extended operation is included. This appendix also includes FSAR content changes that are to be inserted into applicable existing FSAR sections that discuss the same subject as the TLAA covered in Section 4 of this application. Content changes are also being made to some FSAR sections to reflect the requirements of Aging Management Programs.

Appendix B1.0, Aging Management Programs, describes the aging management programs and activities and demonstrates that the aging effects on the components and structures within the scope of the license renewal rules will be managed such that they will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. Where the PBNP programs are consistent with corresponding programs in NUREG-1801, the appropriate NUREG-1801 program is referenced.

Appendix C is not used for this application.

Appendix D1.0, Technical Specification Changes, concludes that no technical specification changes are necessary to manage the effects of aging during the period of extended operation.

Appendix E, Environmental Report, contains an environmental report analyzing the potential environmental impacts of license renewal, as provided for in NRC regulations 10 CFR 51.53(c) and 10 CFR 54.23. The NRC requires license renewal applicants to provide the NRC with input, in the form of an environmental report, that the NRC will use to meet NEPA requirements as they apply to license renewal [10 CFR 51.53(c)].

The NRC has determined that nuclear power plant license renewal decisions are major federal actions requiring preparation of an environmental impact statement [10 CFR 51.20(a)(2) and 51.95(c)]. In an effort to streamline the license renewal environmental review, the NRC conducted a generic analysis and published the results in NUREG-1437, Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants (GEIS). To fulfill NEPA requirements, the NRC is required to publish site-specific analyses in the form of a supplemental environmental impact statement to the GEIS.

The information in Section 2, Section 3, and Appendix B fulfills the requirements in 10 CFR 54.21(a). Section 1.4 discusses how the requirements of 10 CFR 54.21(b) will be met. The information in Section 4 fulfills the requirements in 10 CFR 54.21(c). The information in Appendix A and Appendix D fulfill the requirements in 10 CFR 54.21(d) and 10 CFR 54.22, respectively. The Environmental Report, as required by 10 CFR 54.23, is provided with this PBNP License Renewal Application as Appendix E.

1.2 Plant Description

The two nuclear power units designated as PBNP Units 1 and 2 are located in east central Wisconsin (Manitowoc County) on the west shore of Lake Michigan about 30 miles SE of Green Bay and about 90 miles NNE of Milwaukee. The Units 1 and 2 reactors are Westinghouse designed, pressurized light-water moderated and cooled systems. Each unit was originally licensed at a maximum core thermal power output of 1518.5 MWt. Each steam and power conversion system, including its turbine generator, was originally designed to permit generation of 523.8 MW of gross electrical power. Each unit has undergone a low pressure turbine retrofit modification which increases the unit design output to 537,960 kWe. In 2003, a measurement uncertainty recapture power uprate was performed increasing each unit’s rated thermal power level to 1540 MWt.

Descriptions of PBNP Units 1 and 2 systems and structures can be found in the Final Safety Analysis Report (FSAR). Additional descriptive information about Units 1 and 2 systems, structures, and components is provided in Sections 2, 3, and 4 of this application, and references to the FSAR are provided where pertinent.

The current Unit 1 license (Facility Operating License No. DPR-24) expires on October 5, 2010, and the current Unit 2 license (Facility Operating License No. DPR-27) expires on March 8, 2013. NMC will be named as the exclusive licensed operator on the renewed operating licenses. Wisconsin Electric Power Company will be named as the exclusive owner licensee on the renewed operating licenses.

1.3 Information Required by 10 CFR 54.17 and 10 CFR 54.19

1.3.1 Name of Applicant

Nuclear Management Company (NMC), the operating licensee, hereby applies for renewed operating licenses for Point Beach Nuclear Plant Units 1 and 2. NMC submits this application individually and as agent for the owner licensee named on the operating licenses. The owner licensee is Wisconsin Electric Power Company (WEPCo) doing business under the name We Energies.

1.3.2 Address of Applicant

Nuclear Management Company, LLC
700 First Street
Hudson, Wisconsin 54016

Wisconsin Electric Power Company
231 West Michigan Street
Milwaukee, Wisconsin 53203

Address of PBNP:

Point Beach Nuclear Plant
6610 Nuclear Road
Two Rivers, Wisconsin 54241

1.3.3 Description of Business or Occupation of Applicants

Nuclear Management Company, LLC (NMC)

NMC is engaged in the operation of nuclear power plants. NMC operates PBNP Units 1 and 2 for WEPCo; Duane Arnold Energy Center for Interstate Power and Light Company a subsidiary of Alliant Energy Corporation, Central Iowa Power Cooperative and Corn Belt Power Cooperative; Prairie Island Nuclear Generating Plant and Monticello Nuclear Generating Plant for Northern States Power Company, a subsidiary of Xcel Energy Inc.; Palisades Nuclear Plant for Consumers Energy Company, a subsidiary of CMS Energy Corporation; and Kewaunee Nuclear Power Plant for Wisconsin Public Service Corporation and Wisconsin Power and Light Company. The combined electric generation of the six plants is in excess of 4,500 MW.

NMC is the exclusive licensed operator of PBNP, which is the subject of this application.

NMC is organized as a Wisconsin limited liability company and is owned by Alliant Energy Nuclear, LLC, NSP Nuclear Corporation, WEC Nuclear Corporation, WPS Nuclear Corporation and Consumers Energy Company. WEC Nuclear Corporation is a wholly owned subsidiary of Wisconsin Energy Corporation, the parent holding company of WEPCo. WPS Nuclear Corporation is a wholly owned subsidiary of WPS Resources, Inc., the parent holding company of Wisconsin Public Service Corporation. NSP Nuclear Corporation is a wholly owned subsidiary of Northern States Power Company. Alliant Energy Nuclear, LLC is a wholly owned subsidiary of Alliant Energy Corporation, the parent holding company of Wisconsin Power and Light Company. NMC' s corporate purpose is to provide services in connection with the operation and eventual decommissioning of licensed nuclear facilities on behalf of and for the benefit of the owner utilities.

Wisconsin Electric Power Company (WEPCo)

WEPCo is an investor-owned utility, primarily engaged in the generation and distribution of electricity, and is a wholly owned subsidiary of Wisconsin Energy Corporation. WEPCo is the owner licensee of PBNP.

The WEPCo service territory covers the southeastern and eastern portion of the State of Wisconsin and also includes portions of the upper peninsula of the State of Michigan. WEPCo provides electricity, natural gas, and/or steam service in a 13,000-square-mile area in southeastern Wisconsin, the Appleton area, and in northern Wisconsin and Michigan's upper peninsula.

About 2.4 million people live in WEPCo's service areas. To serve these areas, WEPCo operates 24 electric generating facilities with an installed capacity of over 5,800 megawatts (MW) electric, including PBNP.

WEPCo is an electric utility as defined by the NRC regulations at 10 CFR 50.2. Pursuant to the Nuclear Power Plant Operating Services Agreement between WEPCo and NMC, all costs, including costs for the operation, maintenance, repair, decontamination and decommissioning of PBNP and the Independent Spent Fuel Storage Installation at the plant incurred and accrued are liabilities of WEPCo when incurred and accrued, and WEPCo has committed to provide NMC with funds to pay these costs.

WEPCo will be named as the exclusive licensed owner of PBNP on the renewed operating licenses.

1.3.4 Organization and Management of Applicant

WEPCo is a public utility incorporated under the laws of the State of Wisconsin, with its principal office located in Milwaukee, Wisconsin. NMC is a limited liability company incorporated under the laws of the State of Wisconsin, with its principal office located in Hudson, Wisconsin.

WEPCo and NMC are not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. WEPCo and NMC make this application on their own behaves and are not acting as agents or representatives of any other person. The names and business addresses of WEPCo and NMC directors and principal officers are listed below. All persons listed are U.S. citizens.

Wisconsin Electric Power Company

<u>Directors</u>

Name	Address
Richard A. Abdoo	231 West Michigan Street Milwaukee, Wisconsin 53203
John F. Ahearne	231 West Michigan Street Milwaukee, Wisconsin 53203
John F. Bergstorm	231 West Michigan Street Milwaukee, Wisconsin 53203
Barbara L. Bowles	231 West Michigan Street Milwaukee, Wisconsin 53203
Robert A. Cornog	231 West Michigan Street Milwaukee, Wisconsin 53203
Willie D. Davis	231 West Michigan Street Milwaukee, Wisconsin 53203
Gale E. Klappa	231 West Michigan Street Milwaukee, Wisconsin 53203
Ulice Payne, Jr.	231 West Michigan Street Milwaukee, Wisconsin 53203
Frederick P. Stratton, Jr.	231 West Michigan Street Milwaukee, Wisconsin 53203
George E. Wardeberg	231 West Michigan Street Milwaukee, Wisconsin 53203

<u>Principal Officers</u>

Name	Address
Richard A. Abdoo Chairman of the Board, President and Chief Executive Officer	231 West Michigan Street Milwaukee, Wisconsin 53203
Gale E. Klappa President and Chief Executive Officer	231 West Michigan Street Milwaukee, Wisconsin 53203

Frederick D. Kuester Chief Operating Officer	231 West Michigan Street Milwaukee, Wisconsin 53203
Charles R. Cole Senior Vice President	231 West Michigan Street Milwaukee, Wisconsin 53203
Larry Salustro Senior Vice President and General Counsel	231 West Michigan Street Milwaukee, Wisconsin 53203
Kristine M. Krause Vice President - Environmental	231 West Michigan Street Milwaukee, Wisconsin 53203
Walter J. Kunicki Vice President	231 West Michigan Street Milwaukee, Wisconsin 53203
Gerald A. Abood Vice President - Commodity Resources	231 West Michigan Street Milwaukee, Wisconsin 53203
James B. Baillon Vice President - Administrative Services and Supply Chain	231 West Michigan Street Milwaukee, Wisconsin 53203
Anne K. Klisurich Vice President - Financial Management	231 West Michigan Street Milwaukee, Wisconsin 53203
Roman A. Draba Vice President - State Regulatory Affairs	231 West Michigan Street Milwaukee, Wisconsin 53203
Scott A. Patulski Vice President - Fossil Operations	231 West Michigan Street Milwaukee, Wisconsin 53203
Kristine A. Rappe Vice President and Corporate Secretary	231 West Michigan Street Milwaukee, Wisconsin 53203
Richard J. White Vice President Corporate Communications	231 West Michigan Street Milwaukee, Wisconsin 53203
Allen L. Leverett Chief Financial Officer	231 West Michigan Street Milwaukee, Wisconsin 53203
Arthur A. Zintek Vice President - Human Resources	231 West Michigan Street Milwaukee, Wisconsin 53203

Stephen P. Dickenson Controller	231 West Michigan Street Milwaukee, Wisconsin 53203
Jeffery P. West Treasurer	231 West Michigan Street Milwaukee, Wisconsin 53203

Nuclear Management Company, LLC

Directors

Name	Address
Richard A. Abdoo	Wisconsin Electric Power Company 231 West Michigan Street Milwaukee, WI 53203
David W. Joos	Consumers Energy Company 212 West Michigan Ave. Jackson, MI 49201
Michael Sellman	Nuclear Management Company, LLC 700 First Street Hudson, WI 54016
David M. Wilks	Xcel Energy Inc 4653 Table Mountain Dr. Golden, CO 80403
Eliot G. Protsch	Alliant Energy Corporation 200 First Street SE Cedar Rapids, IA 52406
Larry L. Weyers	Wisconsin Public Service Corporation. 700 North Adams St. Green Bay, WI 54307

Principal Officers

Name	Address
Michael B. Sellman President and Chief Executive Officer	700 First Street Hudson, Wisconsin 54016

John Paul Cowan Executive Vice President and Chief Nuclear Officer	700 First Street Hudson, Wisconsin 54016
Benjamin J. Ewers, Jr. Senior Vice President & Chief Financial Officer	700 First Street Hudson, Wisconsin 54016
Jonathan M. Rogoff Vice President, General Counsel, and Secretary	700 First Street Hudson, Wisconsin 54016
Lyle H. Bohn Senior Vice President - Nuclear Support Programs	700 First Street Hudson, Wisconsin 54016
Dean E. Ekstrom Senior Vice President - Business & Operations Support	700 First Street Hudson, Wisconsin 54016
David Wilson Vice President - Nuclear Assessment Programs	700 First Street Hudson, Wisconsin 54016
Douglas E. Cooper Senior Vice President - Group Operations	700 First Street Hudson, Wisconsin 54016
Craig G. Anderson Senior Vice President - Group Operations	700 First Street Hudson, Wisconsin 54016
David Wilson Vice President - Nuclear Operations	700 First Street Hudson, Wisconsin 54016
Gary D. Van Middlesworth SIte Vice President - Point Beach Nuclear Plant	6590 Nuclear Road Two Rivers, Wisconsin 54241

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

NMC requests renewal of the Class 104b operating licenses for PBNP Units 1 and 2 (license numbers DPR-24 and DPR-27, respectively) for a period of 20 years beyond the expiration of the current licenses. For Unit 1 (DPR-24), license renewal would extend the operating license from midnight October 5, 2010, until midnight October 5, 2030. For Unit 2 (DPR-27), license renewal would extend the operating license from midnight March 8, 2013, until midnight March 8, 2033. This application includes a request for renewal of those NRC source material, special nuclear material, and byproduct material licenses that are included within the current operating licenses and that were issued pursuant to 10 CFR Parts 30, 40 and 70.

The facility will continue to be known as the Point Beach Nuclear Plant.

1.3.6 Earliest and Latest Dates for Alterations, if Proposed

NMC does not propose to construct or alter any production or utilization facility in connection with this renewal application. The current licensing basis will be continued and maintained throughout the period of extended operation.

1.3.7 Listing of Regulatory Agencies Having Jurisdiction and News Publications

The Federal Energy Regulatory Commission (FERC) and the Public Service Commission of Wisconsin are the principal regulators of WEPCo's electric operations.

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Ms. Burnie Bridge
Chairperson
Public Service Commission of Wisconsin
610 N Whitney Way
PO Box 7854
Madison, WI 53707-7854

The area news publications and their associated addresses are provided below

Manitowoc Herald Times Reporter
902 Franklin Street
Manitowoc, Wisconsin 54220

1.3.8 Conforming Changes to Standard Indemnity Agreement

The requirements at 10 CFR 54.19(b) state that license renewal applications must include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The current indemnity agreement No. B-41 for PBNP Units 1 and 2 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. 14, lists DPR 24 and DPR 27 as the applicable license numbers. Should the license numbers be changed upon issuance of the renewed licenses, NMC requests that conforming changes be made to Item 3 of the attachment, and any other sections of the indemnity agreement as appropriate.

1.3.9 Restricted Data Agreement

This application does not contain restricted data or other national defense information, nor is it expected that subsequent amendments to the license application will contain such information. However, pursuant to 10 CFR 54.17(g) and 10 CFR 50.37, NMC, as a part of the application for a renewed operating license, hereby 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 Parts 25 and/or 95.

1.4 Current Licensing Basis Changes During NRC Review

Each year, following the submittal of the PBNP License Renewal Application and at least three months before the scheduled completion of the NRC review, PBNP will submit amendments to the application pursuant to 10 CFR 54.21(b). These revisions will identify any changes to the current licensing basis that materially affect the contents of the License Renewal Application, including the FSAR supplements and any other aspects of the application.

1.5 Abbreviations

This section contains the abbreviations that pertain to the administrative and technical information within the license renewal application. The abbreviations that pertain to the environmental information are included as part of Appendix E (Environmental Report).

AAC	Alternate Alternating Current
AC	Alternating Current
ACI	American Concrete Institute
ACSR	Aluminum Conductor Steel Reinforced
AEC	Atomic Energy Commission
AF	Auxiliary Feedwater
AFP	Auxiliary Feedwater Pump
AFW	Auxiliary Feedwater
AFWP	Auxiliary Feedwater Pump
AISC	American Institute of Steel Construction
AL	Action Level
AMP	Aging Management Program
AMR	Aging Management Review
AMSAC	ATWS Migrating System Actuation Circuit
ANSI	American National Standards Institute
APPR	Appendix R Drawing
AQ	Augmented Quality
AR	Action Request
ASME	American Society of Mechanical Engineers
ASSY	Assembly
ASTM	American Society for Testing of Materials
ATWS	Anticipated Transients Without a Scram
AUX	Auxiliary

B&W	Babcock and Wilcox
BAW	Babcock and Wilcox
BDE	Blowdown Evaporator
BMI	Bottom Mounted Instrument
BOP	Balance of Plant
BS	Boron Recycle
BTP	Branch Technical Position
BWR	Boiling Water Reactor
BWOG	B & W Owners Group
CARDS	Cable and Raceway Data System
CASS	Cast Austenitic Stainless Steel
CB	Control Building
CBD	Class Boundary Diagram
CC	Component Cooling
CCCW	Closed Cycle Cooling Water
CCW	Component Cooling Water
CD-ROM	Compact Disk-Read Only Memory
CE	Condition Evaluation
CFR	Code of Federal Regulations
CHAMPS	Computerized History and Maintenance Planning System
CHECWORKS	The suite of products developed to evaluate power plants for the most common forms of corrosion that degrade their performance and shorten the operating life of critical components.
CIV	Containment Isolation Valve
CLB	Current Licensing Basis
CLRT	Containment Leak Rate Test
CMAA	Crane Manufactures Association of America

CMS	Consumers Energy
Co	Company
CPCI	Containment Pressure Condensate Isolation
CR	Condition Report or Control Room or Count Rate or Cryogenic
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CS	Carbon Steel, Containment Spray, or Condensate System
CSR	Cable Spreading Room
CST	Condensate Storage Tank
CSUP	Component Supports Commodity Group
CUF	Cumulative Usage Factors
CV	Containment Vacuum or Containment Vessel
CVCS	Chemical and Volume Control System
CW	Circulating Water
CWPH	Circulating Water Pump House
DAM	Data Acquisition Modules
DBA	Design Basis Accident
DBD	Design Basis Document
DBE	Design Basis Event
DC	Direct Current
DG	Diesel Generator or Design Guide
DGB	Diesel Generator Building
DGR	Diesel Generator Room
DI	Demineralized Water
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio

EBA	Emergency Breathing Air
ECCS	Emergency Core Cooling System
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EFPY	Effective Full Power Years
EIC	Energy Information Center
EIN	Equipment Identification Number
EL	Elevation
EMPA	Swiss Federal Testing Station
EOCI	Electric Overhead Crane Institute
EOEL	End Of Extended Life
EPA	Electrical Penetration Assemblies
EPDM	Ethylene Propylene Diene Monomer
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQML	Environmental Qualification Master List
EQSS	Environmental Qualification Summary Sheets
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
F	Fahrenheit
FAC	Flow-Accelerated Corrosion
FatiguePro	Automated Cycle Counting and Fatigue Monitoring Program
FE	Flow Element
FERC	Federal Energy Regulatory Commission
FHAR	Fire Hazards Analysis Report

FP	Fire Protection
FPER	Fire Protection Evaluation Report
FM	Frequency Modulation
FOA	Forced Oil-Air
FSAR	Final Safety Analysis Report
FSER	Final Safety Evaluation Report
GALL	Generic Aging Lessons Learned
GDC	General Design Criterion
GEIS	Generic Environmental Impact Statement
GL	Generic Letter
GLD	Green Line Drawing
GSI	Generic Safety Issues
GT	Gas Turbine
GTG	Gas Turbine Generator
GTR	Generic Technical Report
HA	Hydrazine Addition
HAZ	Heat-Affected Zone
HELB	High Energy Line Break
HEPA	High Efficiency Particulate Filter
HMWPE	High Molecular Weight Polyethylene
Hr	Hour
HVAC	Heating, Ventilation and Air Conditioning
HVSAT	High Voltage Station Auxiliary Transformer
HX	Heat Exchanger
I&C	Instrumentation & Controls
I/P	Current to Pressure Converter

IA	Instrument Air
IASCC	Irradiation Assisted Stress Corrosion Cracking
ID	Identification
IE	Inspection and Enforcement
IEB	Inspection and Enforcement Bulletin
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IF	Intended Function
IGA	Intergranular Attack
IGSCC	Intergranular Stress Corrosion Cracking
ILRT	Integrated Leak Rate Test
IN	Information Notice or Inch
INPO	Institute of Nuclear Power Operations
IPA	Integrated Plant Assessment
IR	Insulation Resistance or Inspection Report
ISG	Interim Staff Guidance
ISI	Inservice Inspection Report
ITG	Issues Task Group
IWB	Requirements for Class 1 Components of Light-Water Cooled Power Plants
IWC	Requirements for Class 2 Components of Light-Water Cooled Power Plants
IWD	Requirements for Class 3 Components of Light-Water Cooled Power Plants
IWE	Requirements for Class MC and Metallic Liners of Class CC Components if Light-Water Cooler Power Plants
IWF	Requirements for Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants
IWL	Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants

K_{IC}	Reference Stress Intensity Factor As A Function Of the Metal Temperature (T) and the Metal References Nil-Ductility Temperature (RT_{NDT})
KIP	1000 lb; or 1 Kilo-pound
K_{IR}	ASME Fracture Toughness Curve
Ksi	One KIP per Square Inch, 1000 psi
K VAC	Kilovolts Alternating Current
KWe	Kilowatt Electric
Lb	Pound
LBB	Leak-Before-Break
LEFM	Leading Edge Flow Meter
LER	Licensee Event Report
LLC	Limited Liability Company
LO	Lube Oil
LOCA	Loss-Of-Coolant-Accident
LR	License Renewal
LRA	License Renewal Application
LRDB	License Renewal Database
LTOP	Low-Temperature Overpressure Protection
LVSAT	Low Voltage Station Auxiliary Transformer
LWR	Light Water Reactor
Mat'l	Material
MIC	Microbiologically Induced Corrosion
MIRVP	Master Integrated Reactor Vessel Surveillance Program
Misc.	Miscellaneous

MRP	Materials Reliability Program
MRR	Metering, Relaying and Regulation
MRV	Minimum Required Prestressing Force or Value
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MT	Magnetic Particle Test
MW	Megawatts
MWD	Megawatt-Day
MWt	Megawatt Thermal
N	North
NA OR N/A	Not Applicable
NaOH	Sodium Hydroxide
NCR	Non-Conformance Report
NDE	Non-Destructive Examination
NE	Northeast
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NES	Nuclear Engineering Services
NFPA	National Fire Protection Association
NMC	Nuclear Management Company
NNE	North-North East
Non-VSR	Non Vital Switchgear Room
NP	Nuclear Procedure
NPS	National Pipe Size
NQAP	Nuclear Quality Assurance Program
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center

NSP	Northern States Power
NSR	Non-Safety Related
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Utility Management and Resource Council
NUREG	Nuclear Regulation Document
OCCW	Open Cycle Cooling Water Program
ODSCC	Outside Diameter Stress Corrosion Cracking
OEM	Original Equipment Manufacturer
P&ID	Piping and Instrument Diagram
P-T	Pressure Temperature
PAB	Primary Auxiliary Building
PACV	Post Accident Containment Ventilation System
PBNP	Point Beach Nuclear Plant
PDI	Performance Demonstration Initiative
PLL	Predicted Lower Limit
PM	Preventative Maintenance
PORV	Power-Operated Relief Valve
PPB	Parts Per Billion
PPCS	Plant Process Computers System
PRT	Pressurizer Relief Tank
PS	Pipe Support
PSI	Pounds Per Square Inch
PSIG	Pounds Per Square Inch Gauge
PSPM	Periodic Surveillance and Preventative Maintenance
PT	Penetrant Testing
PTS	Pressurized Thermal Shock
PVC	Poly Vinyl Chloride

PW	Potable Water
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
PZR	Pressurizer
Q-List	Quality List
QA	Quality Assurance
RAI	Request for Additional Information
RC	Reactor Coolant
RCCA	Rod Control Cluster Assembly
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
REV	Revision
RG	Regulatory Guide
RH	Residual Heat
RHR	Residual Heat Removal
RH/SI	Residual Heat/Safety Injection
RI-ISI	Risk Informed Inservice Inspection Program
RM	Radiation Monitoring
RMW	Reactor Makeup Water
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RSG	Replacement Steam Generator
RTD	Resistance Temperature Detectors
RT_{NDT}	Reference Temperature for Nil Ductility Transition
RT_{PTS}	Reference Temperature for Pressurized Thermal Shock

RV	Reactor Vessel or Relief Valve
RVH	Reactor Vessel Head
RVI	Reactor Vessel Internals
RWST	Refueling Water Storage Tank
S&PC	Steam and Power Conversion
SA	Service Air
SBCC	Site Boundary Control Center
SBO	Station Blackout
SC	Structure and Component
SCBA	Self-Contained Breathing Apparatus
SCC	Stress Corrosion Cracking
SE	South East
SER	Safety Evaluation Reports
SF	Spent Fuel
SFP	Spent Fuel Pool
SG	Steam Generator
SGBD	Steam Generator Blowdown
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SOC	Statement Of Considerations
SOER	Significant Operating Event Report
SOV	Solenoid Operated Valve
SPING	System-Level Particulate, Iodine and Nobel Gas Monitor
SR	Safety Related
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for License Renewal
SS	Stainless Steel or Sampling System

SSAR	Safe Shutdown Analysis Report
SSC	System, Structure, or Component
SSEL	Safe Shutdown Equipment List
STP	Sewage Treatment Plant
SW	Service Water
TAC	Training Advisory Committee
T_{AVG}	RCS Average Temperature
TB	Turbine Building
TID	Total Integrated Dose
TLAA	Time-Limited Aging Analysis
TR	Technical Report
TRM	Training Requirements Manual
TS	Technical Specifications
TSC	Technical Support Center
U1	Unit 1
U2	Unit 2
U.S.	United States
USE	Upper Shelf Energy
USI	Unresolved Safety Issue
USNRC	United States Nuclear Regulatory Commission
UT	Ultrasonic Testing
UTS	Ultimate Tensile Strength
UV	Ultraviolet
VAC	Volts-Alternating Current
VCT	Volume Control Tank
VDC	Volts-Direct Current

VHP	Vessel Head Penetration
VNBI	PAB Battery and Inverter Room Ventilation System
VNCC	Containment Cooling System
VNCF	Containment Clean-up System
VNCOMP	Computer Room Ventilation System
VNCR	Control Room Ventilation System
VNCRD	Control Rod Drive Cooling System
VNCSR	Cable Spreading Room Ventilation System
VNDG	Diesel Generator Building Ventilation System
VNDRM	Drumming Area Ventilation Sub-system
VNPAB	Primary Auxiliary Ventilation Sub-system
VNPH	Circ. Water Pumphouse Ventilation Sub-system
VNPSE	Containment Purge Supply and Exhaust Sub-system
VNRAD	Radwaste Ventilation Sub-system
VNRC	Reactor Cavity Cooling Sub-system
VNRF	Refueling Cavity Ventilation Sub-system
Vol.	Volume
VPNPD	Vice President Nuclear Power Department
Vs.	Versus
VT	Visual Examination
WCAP	Westinghouse Commercial Atomic Power
WD	Waste Disposal
WE	Wisconsin Electric
WEC	Wisconsin Energy Corporation
WEPCo	Wisconsin Electric Power Company
WL	Waste Liquid
WPS	Wisconsin Public Service
WO	Work Order

WOG	Westinghouse Owners Group
WT	Water Treatment
XLPE	Cross-Linked Polyethylene
YARD	Yard Structures
Zn	Zinc

1.6 Communications

Written communications on this application should be directed to:

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And

Mr. Douglas F. Johnson
Director, Plant Life Cycles
Nuclear Management Company, LLC
700 First Street
Hudson, WI 54016

Section 1.0 References

1. 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, U.S. Nuclear Regulatory Commission.

2. 10 CFR 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions, U.S. Nuclear Regulatory Commission.

3. RIS 2001-05, NRC Regulatory Issue Summary 2001-05 Guidance on Submitting Documents to the NRC By Electronic Information Exchange or on CD-ROM

4. NEI 95-10, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 -The License Renewal Rule, Rev. 4 draft, Nuclear Energy Institute.

5. NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, U.S. Nuclear Regulatory Commission, July 2001.

6. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, U.S. Nuclear Regulatory Commission, July 2001.

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

2.1 Scoping and Screening Methodology

2.1.1 Introduction

The Scoping Process defined the entire plant in terms of major systems and structures and identified their system-level functions. All of these systems and structures were then evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (2), and (3), to determine whether they performed or supported an intended function for responding to a design basis event, or performed or supported a specific requirement for one of five license renewal regulated events.

Even if only a portion of a system or structure met the scoping criteria of 10 CFR 54.4, the system or structure was identified as in-scope for license renewal. A Boundary Evaluation was then performed that specified which components performed or supported the system intended functions identified previously. As a result, not all components within an in-scope system or structure were considered in-scope for license renewal. The in-scope boundary is depicted on the License Renewal Boundary Drawings which show the in-scope components in color.

The Screening Process evaluated the in-scope structures and components to determine which ones were long-lived and passive. The result of the screening process was a list of long-lived, passive structures and components that would be subject to an aging management review.

Figure 2.1-1 provides a basic diagram depicting how the scoping and screening process was executed.

The Aging Management review methodology is discussed in Section 3.0 of the LRA.

A number of different information sources played a role in how scoping and screening was performed at PBNP. These are discussed here as background information to the scoping and screening process.

2.1.1.1 Plant Information Sources

2.1.1.1.1 Current Licensing Basis

The Current Licensing Basis (CLB) is defined in 10 CFR 54.3. The CLB for PBNP has been defined in accordance with this guidance and is considered to consist of the Final Safety Analysis Report (FSAR), the Technical

Specifications, and the commitments-in-effect contained in docketed licensing correspondence.

2.1.1.1.2 **Design Basis Events (DBEs)**

The safety classifications for SSCs at PBNP were established based on a set of Design Basis Events (DBE), which include design basis accidents, anticipated operational occurrences, natural phenomena, and external events. The DBEs considered are consistent with the PBNP CLB. Chapter 14 of the PBNP FSAR provides the DBE accident analyses for PBNP. These analyses include both design basis accidents and anticipated operational occurrences. Additional information regarding many of these DBEs can be found in Volume 35 of the Design Basis Documents (DBDs). Natural phenomena and external events are not analyzed in Chapter 14 of the FSAR, but are described in Chapter 2 and in appropriate sections of Volume 41 of the DBDs. Structures designed to withstand DBE natural phenomena and external events are described in Chapter 5 of the FSAR. DBDs are “For Information” and are not considered CLB documents.

2.1.1.1.3 **Safety Classifications**

Safety classifications for systems, structures, and components at PBNP fall into one of the following categories as indicated in plant procedures.

- Safety Related (SR)
- Augmented Quality (AQ)
- Non-QA Scope

These classification categories are defined below. Items identified as safety related or Augmented Quality are within QA Scope and are controlled under the QA program described in the NQAP Manual. These safety classifications have been applied to all the components in CHAMPS, as indicated in the component's Q-List information, and are consistent with information reflected on the Green Line Drawings (see Section 2.1.1.1.6).

The Q-list consists of various data fields controlled and maintained within the CHAMPS database (see Section 2.1.1.1.4) used to identify safety related and augmented quality equipment necessary to mitigate certain postulated DBAs.

Safety Related

Safety related structures, systems, and components are those that are relied upon to remain functional during and following design basis events to ensure:

- The integrity of the reactor coolant pressure boundary
- The capability to shutdown the reactor and maintain it in a safe shutdown condition
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures in excess of 10 CFR 100 guidelines.

An item is considered “relied upon” if failure of the item, in conjunction with a single failure, results in the inability to perform a safety function (assuming that the item is designed for that purpose and assuming that offsite power may or may not be available).

The safety related classification includes Electrical/Instrumentation and Control (I&C) systems whose purpose is to initiate automatic safety features or operator actions that are required for accident prevention and mitigation, or to shutdown the reactor and maintain it in a safe shutdown condition.

Augmented Quality

Augmented Quality applies to non-safety related items for which a regulatory or design basis commitment has been made, or that for plant availability reasons, PBNP has implemented special controls. These special controls assure the reliability of these components to prevent undue risk to the health and safety of the public or loss of service should they fail or malfunction.

Review of PBNP’s classification criteria reveals that certain structures, and components classified as AQ do not meet the criteria of 10 CFR 54.4(a), and as a result are not in the scope of license renewal.

Non-QA Scope

Those components that do not perform a Safety Related or Augmented Quality QA Scope function as detailed in the definitions above, are defined as non-QA scope.

QA Codes

QA Codes were developed at Point Beach to track the bases for determining why an SSC was characterized as SR or AQ. QA scoped components are relied upon at PBNP to perform safety related and Augmented Quality functions to mitigate design basis accidents and other postulated events. The QA codes are considered part of the Q-list documentation. QA Codes consist of unique numbers and are applied to individual components within CHAMPS. A single component may have multiple QA Codes assigned to it.

During the Scoping Process, the Q-List provided information regarding the quality classification and the functions credited with Quality Assurance requirements. QA Codes for PBNP systems and structures identified the QA credited functions, which provided input to system-level functions and boundary evaluations for license renewal.

2.1.1.1.4 **CHAMPS Equipment Database**

Component information for systems and equipment at PBNP can be found in the CHAMPS (Computerized History and Maintenance Planning System) equipment database. CHAMPS is a controlled, relational database system that is used by the site. CHAMPS data is stored in only one place in the system even though it may be entered, modified, or displayed at multiple locations. Not all components are uniquely identified in CHAMPS. CHAMPS does not include items such as cables, raceways, conduits, fireproofing, general construction items (e.g., nuts, bolts), or consumable materials (e.g., boric acid, diesel fuel, resins, etc.).

CHAMPS is the repository for Point Beach Q-List information and also contains multiple component data fields used for license renewal, including design-related information and maintenance-related information. Additional information that can be found in CHAMPS includes seismic classification, QA Codes, location, EQ, FP, App R, ATWS, Reg. Guide 1.97 applicability, component tag ID, equipment type, power source, plant system, and component description, as appropriate. Many of these data fields were downloaded into the License Renewal database (see Section 2.1.1.2.1).

2.1.1.1.5 **Design Basis Documents**

The Design Basis Documents (DBDs) were prepared for a number of support and accident mitigation systems, selected licensing issues, and FSAR Chapter 14 Accident Analyses. DBDs are a tool to explain the requirements behind the design rather than describing the design itself. DBDs are not CLB documents. DBDs are intended to complement information obtained from other sources and to identify potential reference documents. These reference documents include:

- FSAR and Technical Specifications
- Industry Codes, Standards, and Regulations

- Regulatory Correspondence and Documents
- Technical Correspondence, Analyses, and Reports
- Calculations
- Drawings, Specifications, Modifications, and Other Documents
- Vendor Reports, Specifications, and Drawings

2.1.1.1.6 Drawings

Plant drawings were used as references when performing system, structure, and component evaluations for license renewal. There are three special types of drawings that are used as references when performing mechanical system and component evaluations: Class Boundary Diagrams (CBDs), Green Line Drawings (GLDs), and Appendix R Drawings (APPRs).

Class Boundary Diagrams (CBDs)

The CBDs are shaded overlays of existing Piping and Instrument Diagrams (P&IDs) which depict the ASME Code Boundaries (Class 1, 2, and 3) for Point Beach.

Green Line Drawings (GLDs)

The GLDs are colored overlays of existing P&IDs that depict Safety Related (SR), Augmented Quality (AQ), and EQ equipment, using green, blue, and red color respectively.

Appendix R Drawings (APPRs)

The APPRs are shaded overlays of existing P&IDs that depict flow paths necessary during Appendix R scenarios.

LR Boundary Drawings

The LR Boundary Drawings are colored overlays of PBNP drawings that depict the in-scope portions of plant SSCs (which are shown in color). The LR Boundary Drawings were generated during the Boundary Evaluation phase of the scoping process (see Section 2.1.2.3), and utilized the drawings referenced above, along with component-level scoping information.

2.1.1.2 License Renewal Tools

2.1.1.2.1 License Renewal Database

The License Renewal database (LRDB) provides the information repository for system, structure, and component evaluations, and it provides the platform for the project's administration of equipment data and output reports. The database is consistent with the process guidance in NEI 95-10 and the process requirements of 10 CFR 54.

2.1.1.2.2 License Renewal Database Population

The license renewal database was initially populated with assets from the PBNP CHAMPS equipment database. Each PBNP system was matched to its appropriate license renewal system and the components from the CHAMPS database were electronically populated into the license renewal database. Component information within CHAMPS relevant to license renewal such as the equipment identifications, descriptions, equipment's plant locations, and Q-List information, was included.

It is important to note that not all systems/components from CHAMPS were included in the population of the license renewal database. Those items that reflected systems and equipment groups/types that did not represent permanently installed equipment were not downloaded. The components in these systems and equipment groups/types were reviewed to ensure no components were omitted that had any potential to be considered in-scope for license renewal.

2.1.1.2.3 License Renewal Database Output

The LRDB is just a tool to assist in performing the license renewal process for PBNP. As such, it is not the official record for documentation. Reports that were generated from the LRDB were reviewed and approved, and are considered the official QA records.

2.1.1.3 Interim Staff Guidance Discussion

During recent license renewal application reviews the NRC staff identified eight issues for which additional staff and industry guidance clarification was necessary. They are:

1) Station Blackout Scoping (ISG-02)
2) Concrete Aging Management Program (ISG-03)
3) Fire Protection System Piping Aging Management (ISG-04)
4) Identification and Treatment of Electrical Fuse Holders (ISG-05)
5) Identification and Treatment of Housings for Active Components (Draft ISG-06)
6) Scoping Guidance for Fire Protection (FP) Systems, Structures, and Components (Draft ISG-07)

7) Interpretation of 10 CFR 54.4(a)(2) (Draft ISG-09)

8) Addition of Generic Aging Lessons Learned (GALL) Aging Management Program (AMP) XI.M35, “One-Time Inspection of Small-Bore Piping,” for License Renewal (Draft ISG-12)

Following is a discussion of the general process used during the License Renewal Integrated Plant Assessment at PBNP to apply the draft or final guidance (as applicable) for each of these areas:

2.1.1.3.1 Station Blackout Scoping (ISG-02)

NRC guidance on this issue is as follows: “Consistent with the requirements specified in 10 CFR 54.4(a)(3) and 10 CFR 50.63(a)(1), the plant system portion of the Offsite Power System should be included within the scope of license renewal.” Further clarification was provided which stated that, “the staff has determined that the plant system portion of the Offsite Power System that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the Offsite Power System transformers (Startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system, and the associated control circuits and structures.”

FSAR Sections 7.5.3.3.b (Emergency Lighting), 7.5.3.3.a and 9.8.3 (Ventilation), 8.4 (4160 VAC), 8.5 (480 VAC), 8.6 (120 VAC), 8.8 (Diesel Generators), 8.9 (Gas Turbine), and 10.2.3 (AFW) all address portions of the equipment for response to a station blackout and the station’s methodology for coping with a station blackout. The SSCs assumed to be necessary for the coping and recovery strategy to satisfy 10 CFR 50.63 criteria, including both primary and alternative SSCs available to manage the event, are included within the scope of License Renewal. Additional specific information on this methodology is included in FSAR Appendix A.1, “Station Blackout.”

As stated above, the License Renewal regulatory guidance also mandates the inclusion of selected offsite power SSCs which may be used for restoration of offsite power following an SBO event beyond those SSCs identified in the regulatory commitments made to satisfy 10 CFR 50.63 criteria. Therefore, the SSCs that provide for restoration of offsite power following an SBO condition, in accordance with the current License Renewal regulatory interpretation, are also considered within the scope of License Renewal.

2.1.1.3.2 **Concrete Aging Management Program (ISG-03)**

As a result of the performance of AMRs for in-scope concrete components, PBNP has concluded that many of these components do not require aging management for the period of extended operation. This conclusion is based on a review of the material of construction, the environment, and industry and plant-specific operating experience for these components. However, for accessible concrete portions of the containment, PBNP has implemented the examination requirements and inspection intervals of ASME Section XI, Subsection IWL as an aging management program (AMP) for the period of extended operation. Other structures subject to an aging management review will receive similar inspections as part of the Structures Monitoring Program. NUREG-1801 does not recommend further evaluation of concrete components in inaccessible areas for which the applicant can demonstrate a non-aggressive environment. The environment evident for the inaccessible concrete at PBNP is not aggressive; therefore, further evaluation of normally inaccessible structures will only be considered when excavations allow access or when aging effects on accessible concrete structures indicate that potential detrimental aging effects could also be occurring in inaccessible areas.

2.1.1.3.3 **Fire Protection System Piping Aging Management (ISG-04)**

In a December 2, 2002, letter from the NRC to NEI entitled, “Interim Staff Guidance (ISG)-04: Aging Management Of Fire Protection Systems For License Renewal,” the NRC provided changes to their previous guidance to the industry on aging management for passive SSCs comprising fire protection. As outlined in the program description in NUREG-1801 Chapter XI.M26, Fire Protection, and Chapter XI.M27, Fire Water Systems, PBNP intends to provide for aging management in a manner consistent in most part with the proposed guidance. At PBNP these two programs are combined into the Fire Protection Program.

This program includes guidance as to the performance of volumetric inspections and/or wall thickness evaluations, and visual as well as other techniques.

2.1.1.3.4 **Identification and Treatment of Electrical Fuse Holders (ISG-05)**

Consistent with the requirements specified in 10 CFR 54.4(a) and ISG-05 (Reference 8), fuse holders (including fuse clips and fuse blocks) are considered to be passive electrical components. Fuse holders are scoped, screened, and included in the aging management review (AMR) in the same manner as terminal blocks and other types of electrical connections. However, fuse holders inside the enclosure of an active component, such as control boards, control panels, switchgear, power supplies, power inverters, battery chargers, circuit boards, and other electrical equipment, are considered to be piece parts of the larger assembly. Since piece parts and subcomponents in such an enclosure are inspected regularly and maintained as part of the PBNP normal maintenance and surveillance activities, they are considered not subject to an AMR. Fuse holders perform a primary function similar to other types of electrical connections by providing an electrical circuit to deliver rated voltage, current, or signals. These intended functions meet the criteria of 10 CFR 54.4(a). Additionally, these intended functions are performed without moving parts or without a change in configuration or properties as described in 10 CFR 54.21 (a)(1)(i). Fuse holders are therefore passive, long-lived electrical components within the scope of license renewal and subject to an AMR. Therefore, aging management of fuse holders would be required for those cases where fuse holders are not considered subcomponent parts of a larger assembly. However, no fuse holders have been identified at PBNP that are located outside of a larger active component and thus no separate aging management program has been proposed for fuse holders.

2.1.1.3.5 **Identification and Treatment of Housings for Active Components (Draft ISG-06)**

The Statements of Consideration for 10 CFR 54 provides the License Renewal Rule philosophy that, during the extended period of operation, safety related functions should be maintained in the same manner and to the same extent as during the current licensing term. Examples of structures and components that perform passive functions are listed in 10 CFR 54.21(a)(1)(ii), which states, “These structures and components include, but are not limited to, pump casings, valve bodies. . .”

Pumps and valves were just an example here, meant to focus the AMR process on the passive function of an SSC. That passive function is not limited to the pressure boundary of the Reactor Coolant System. The exclusion of an SSC due to its active nature only applies to that portion of the SSC with an active function and not to those portions of the SSC with a passive function. Therefore, at PBNP, fan housings and fire damper housings are considered to be within scope and subject to an AMR.

2.1.1.3.6 Scoping Guidance for Fire Protection (FP) Systems, Structures, and Components (Draft ISG-07)

The PBNP Fire Protection (FP) scoping takes into consideration the interim staff guidance (ISG) that was developed to clarify the requirements of 10 CFR 54.4(a)(3) as it pertains to 10 CFR 50.48. This includes General Design Criterion 3, Appendix R and associated license conditions, and the proposed revisions to NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” concerning incorporation of this guidance into the improved license renewal guidance documents (NUREG-1800 and/or NUREG-1801) when this ISG is finalized.

The Fire Protection Program was developed to maintain compliance with 10 CFR 50.48, Appendix R to 10 CFR 50, and Appendix A of Branch Technical Position APCSB 9.5-1 by meeting the following objectives in fire areas important to safety (the effects of fires on SSCs “important to safety” are addressed in 10 CFR 50.48 and provide a general level of protection that is afforded to all systems, not only those required for safe shutdown):

- Reduce the likelihood of fires.
- Promptly detect and extinguish fires that do occur.
- Maintain safe-shutdown capability if a fire does occur.
- Prevent release of a significant amount of radioactive material if a fire does occur.

The PBNP FPP also includes the FP equipment required for insurance purposes for facilities such as the NES Office/Training Building including the records facilities, Energy Information Center, and Site Boundary Control Center, none of which have any safety significance. These SSCs that are not important to safety have been excluded from the scope of license renewal for FP.

A review has been performed to identify the specific SSCs that fall within the scope of license renewal for the FPP including the SSCs relied upon in the Fire Hazards Analysis. As a result of this review, the following features and equipment have been included within the scope of license renewal for FP:

- Fire detection and suppression equipment
- Fire barriers (includes doors, walls, gap covers, penetration seals, etc.)
- Flood barriers (includes curbs, dikes, etc.)
- Safe shutdown equipment (Appendix R)
- Reactor coolant pump oil collection sub-system

- Fire fighting support (communications, lighting, bottled air)
- Panels
- Post-fire repair equipment (required for cold shutdown)
- Radiant energy shields
- Control room envelope pressure boundary (Halon suppression concentration)
- Combustible containment features (includes berms/dikes around fuel oil tanks, etc.)

The screening methodology applied to the Appendix R post-fire repair equipment that is maintained in storage is discussed in Section 2.1.3.1.1, Screening of Stored Equipment.

This scoping methodology presented above is in accordance with the guidelines of the draft ISG.

2.1.1.3.7 **Interpretation of 10 CFR 54.4(a)(2) (Draft ISG-09)**

By letters dated December 3, 2001, and March 15, 2002, the Nuclear Regulatory Commission (NRC) issued a staff position to the Nuclear Energy Institute (NEI) which described areas to be considered and options it expects licensees to use to determine what systems, structures, or components (SSCs) meet the 10 CFR 54.4(a)(2) criterion.

The December 3, 2001, letter provided the approaches the NRC considers acceptable to determine which piping systems should be included in-scope based on the 10 CFR 54.4(a)(2) criterion. The March 15 letter, further described the staff's expectations for the evaluation of non-piping SSCs to determine which additional non-safety related SSCs are within scope.

PBNP has used the above referenced letters along with industry input on implementing these expectations, in order to develop our methodology scoping per 10 CFR 54.4(a)(2). Components meeting the scoping criterion of 10 CFR 54.4(a)(2) will generally fall into three categories.

1. Current Licensing Basis (CLB). PBNP's CLB includes a number of specific issues that identify NSR SSCs that meet the intent of 10 CFR 54.4(a)(2).
2. NSR SSCs directly connected to SR SSCs (typically piping systems).
3. NSR SSCs that are not directly connected to SR SSCs. In this case, two options are provided, a mitigative option or a preventive option.

Categories 2 and 3 are intended to apply to all NSR SSCs that may not be specifically identified in the CLB (not included in category 1).

A more detailed discussion of this methodology is available in Section 2.1.2.1.2.

2.1.1.3.8 Addition of Generic Aging Lessons Learned (GALL) Aging Management Program (AMP) XI.M35, "One-Time Inspection of Small-Bore Piping," for License Renewal (Draft ISG-12)

The fourth interval PBNP Inservice Inspection Program implements risk informed selection criterion for Class 1 piping welds. The Risk Informed Inservice Inspection (RI ISI) Program for Class 1 piping welds includes all Class 1 piping, except for piping 1-inch NPS and smaller. The RI ISI Program inspections of piping welds less than 4-inch NPS will include volumetric examinations, with the exception of socket welded connections. Until a meaningful volumetric inspection technique is created for the geometry presented by socket welds, a surface examination will be substituted.

Implementation of the RI ISI Program during the last inspection interval of the current license period will provide 10 years of volumetric inspection data on high and medium risk small bore piping locations greater than 1-inch NPS. Since small bore piping will receive volumetric inspections through the RI ISI Program, there is no need for a one-time special inspection of small bore piping to ensure that cracking is not occurring.

Crack initiation and growth due to SCC was identified as an aging effect requiring management in small-bore (<NPS 4) reactor coolant system piping and branch lines. Aging management of service-induced cracking will be accomplished by a combination of the Water Chemistry Control Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. PBNP has implemented a Risk Informed ISI program, and as part of this transition, some small bore (<NPS 4) RCS locations were identified for inspection. These inspections of small bore RCS piping will meet the intent of the one-time inspections referenced in NUREG-1800.

The proposed combination the Water Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program is an effective means of managing service-induced cracking in small-bore reactor coolant system piping and connected branch lines during the period of extended operation.

2.1.1.4 Consideration of Power Uprating in License Renewal Evaluation Process

Power uprate safety evaluations for the Point Beach Nuclear Plant have been performed to increase the reactor thermal power level from the initial power level of 1518.5 MWt to a maximum power level of 1678 MWt. To accommodate future plant operating conditions at uprated power, the license renewal evaluations considered plant operating conditions of reactor thermal power at both 1518.5 MWt and at possible future power uprated conditions up to 1678 MWt.

2.1.1.4.1 Power Uprate Background

The PBNP power uprate effort performed analyses and evaluations to support a core power uprate from 1518.5 MWt up to a maximum of 1678 MWt for PBNP Units 1 and 2. The NSSS systems, components, and accident analyses for the PBNP power uprate were performed in two stages. The first stage covers a power increase of approximately 8.7% from the initial licensed core power of 1518.5 MWt to 1650 MWt. The second stage covers a possible additional calorimetric mini-uprate of up to 1.7% from the core power of 1650 MWt to 1678 MWt. These two stages result in a combined core power uprate of 10.5 percent. The additional calorimetric mini uprate is achieved through the use of a Leading Edge Flow Meter (LEFM), which yields improved accuracy of the measurement of feedwater flow used in the determination of reactor power.

In conjunction with the uprating, 60-year plant life extension in the component analyses was also evaluated such that the analyses would be bounding for an additional 20 years of operating life. The results of the analyses and evaluations are applicable for operation at any core power level from 1518.5 MWt to the 1678 MWt.

The plan for NRC power uprate submittals reversed the order by first requesting the mini-uprate of 1.4% to 1540 MWt, followed at a future date by an uprate request for 8.7% to1673 MWt. The mini-uprate request was submitted to the NRC on April 30, 2002 and approved by the NRC in a letter dated November 29, 2002. The 8.7% power uprate request may be submitted at some future date.

2.1.1.4.2 License Renewal Considerations of Plant Power Level Conditions

A power uprating, in one or more incremental steps, may be proposed for the Point Beach Nuclear Plant. To eliminate the need to redo any of the License Renewal process as part of or after any uprating, the license renewal evaluations considered plant operating conditions at both 1518.5 MWt and at possible future power uprated conditions of up to 1678 MWt. To achieve this result, the plant parameters of interest which could influence any aging effects were tabulated along with the current design parameters and used in the IPA process and TLAA evaluations. An examination of these and other parameters were used at appropriate steps in the LR processes for each technical discipline, for each TLAA evaluation, and for developing aging management programs. This process was employed to ensure that the evaluations of aging and aging management are performed on the materials and conditions sufficient to bound the most adverse aging at either the initial CLB, intermediate, or any future uprated power levels.

The period considered for these increased power levels were conservatively assumed to commence at the start of the license renewal evaluation process and continue through the period of extended operation.

2.1.1.4.3 **Results of Power Uprate Considerations**

The consideration of power uprate at each of the LR process steps has shown the following:

- Scoping: Power uprate considerations did not change the system scoping criteria or system in-scope results. Therefore, no adjustment to the scoping process was required for either the initial CLB or proposed intermediate and final uprated power levels. Since no new systems were created by power uprating, the scoping performed on existing plant systems was determined to be independent of power level.
- Screening: Power uprate considerations did not change the component screening criteria or boundary definition results. Therefore, no adjustment to the screening process was required for either the initial CLB or proposed intermediate or any future uprated power levels. The power uprate design process must use appropriate materials for the plant environments in which they are to be installed. Since components modified in plant systems as a result of power uprate will be designed to accommodate the final power levels and extended period of operation, the screening performed on current plant components was independent of power level. Any future implementation of power uprate must later confirm that the materials actually used meet this criteria. In the future, any replaced or new components considered for or installed as part of the power uprate implementation process would address license renewal requirements as required by 10 CFR 54.37.

- Aging Management Reviews: Of most concern are the existing passive components in each technical discipline and any change in their environments as a result of the power uprate. These components and environments were examined to assess the effects that power uprate will have on factors which affect aging. Any future implementation of power uprate must later confirm that the materials of construction and the environments have not changed outside the bounds of the AMRs developed from these reviews.
- Aging Management Programs: Programs assigned to manage the aging identified by the aging management reviews were examined for any adjustments required to manage aging for the extended period of operation at the maximum proposed uprated power level and any intermediate power levels approved prior to achieving the maximum uprate power. When a potential impact to a program was identified, this impact was documented in the program basis document in the section addressing power uprate. Any future implementation of power uprate must later confirm that the programs continue to manage aging at the uprated power and any impacts identified during the license renewal evaluation process are addressed by changes to the aging management program.
- Time-Limited Aging Analyses: The proposed power uprate did not introduce any new time-limited aging analyses (TLAAs) based on the PBNP and industry searches, which included plants at higher power levels than PBNP. The TLAAs identified for PBNP were reviewed for their continued validity at the proposed uprated power levels. Where appropriate, recalculations were performed at the bounding uprated power level. Any future implementation of power uprate must later confirm that the TLAAs continue to be valid at the uprated power.

2.1.1.4.4 **Conclusion of Power Uprate Considerations**

Given the considerations described above, the license renewal evaluations performed to support the PBNP License Renewal Application address the initial CLB operating conditions as well as operations at the maximum proposed uprated power level or any intermediate power levels approved prior to achieving the maximum uprate power. When any future power uprate is implemented, changes to the plant components or environments will need to be confirmed to be within the bounds evaluated during the license renewal process and that any identified changes to aging management programs be implemented. When this implementation occurs after the renewed license is issued, these considerations will be addressed as required by 10 CFR 54.37 and as part of the power uprate review.

2.1.2 Scoping Methodology

10 CFR 54 provides specific criteria for determining which systems, structures, and components should be reviewed and evaluated for inclusion in the scope of License Renewal. Specifically, 10 CFR 54.4 of the rule states that:

(a) Plant systems, structures, and components within the scope of this part are:

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

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

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

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

(2) All non-safety related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(I), (ii), or (iii) above.

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

(b) The intended functions that these systems, structures, and components must be shown to fulfill in 10 CFR 54.21 are those functions that are the bases for including them within the scope of License Renewal as specified in paragraphs (a)(1) - (3) of this section.

2.1.2.1 Application of License Renewal Scoping Criterion

2.1.2.1.1 Safety Related Criteria Pursuant to 10 CFR 54.4(a)(1) (Criterion 1)

The first scoping category in 10 CFR 54.4 involves safety related systems, structures, and components. The LR criteria for safety related SSCs are consistent with PBNP’s SR classification criteria and with PBNP’s FSAR. Therefore, SSCs that have a SR designation within CHAMPS (Q-list) are considered in-scope of license renewal. The PBNP Safety Related definition is not identical to the definition within the LR Rule, but the differences (§50.34(a)(1), §50.67(b)(2)) were investigated, and this did not result in any additional components being considered safety related (all components affected were already SR).

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

Overview for Criterion 2 Scoping

The NRC issued their draft Interim Staff Guidance, License Renewal Issue: Scoping of Seismic II/I Piping Systems, dated December 3, 2001 (Reference 7) and clarified it with their March 21, 2002 letter on the same topic. These documents provide additional regulatory guidance on how Criterion 2 scoping is expected to be performed.

Criterion 2 Scoping Methodology

PBNP utilized the draft industry guidance document on Criterion 2 (which is based on the ISG and other applicants responses to Criterion 2 RAIs), to develop our methodology for Criterion 2 scoping. This methodology is summarized below, and is expected to meet the intent of the draft Interim Staff Guidance.

Components meeting the scoping criterion of 10 CFR 54.4(a)(2) will generally fall into three categories.

(1) Current Licensing Basis (CLB). PBNP's CLB includes a number of specific issues that identify NSR SSCs that meet the intent of 10 CFR 54.4(a)(2).

(2) NSR SSCs directly connected to SR SSCs (typically piping systems).

(3) NSR SSCs that are not directly connected to SR SSCs. In this case, two options are provided, a mitigative option or a preventive option.

Categories 2 and 3 are intended to apply to all NSR SSCs that may not be specifically identified in the CLB (not included in category 1). The following discussion is intended to provide the rationale within these three categories, for determining which NSR SSCs will be considered within the scope of License Renewal.

Some PBNP QA Codes were considered equivalent to some Criterion 2 functions. In those cases, the components with those codes were flagged in the LRDB as in-scope.

1) NSR SSCs Identified in the CLB

a. High Energy Line Break (HELB)

NSR whip restraints, jet impingement shields, blow-out panels, etc., that are designed and installed to protect SR equipment from the effects of a HELB, are within the scope of license renewal per 10 CFR 54.4(a)(2). These protective features are typically associated with the structure, and would be addressed in the Civil/Structural area review.

If the HELB analysis assumes that a NSR high energy piping system does not fail or assumes failure only at specific locations, then that piping system must be within the scope of license renewal per 10 CFR 54.4(a)(2), and subject to aging management review in order to ensure those assumptions remain valid.

NOTE: PBNP's CLB HELB definition is a system that is typically >200°F and >275 psig. Systems meeting this definition have been evaluated for HELB within PBNP's CLB, and modified as necessary. While PBNP's definition is less restrictive than the current NRC definition (>200°F or >275 psig), we did review those systems that met the current NRC definition. We found that some of these systems had the potential to affect the function of SR SSCs, and therefore portions of these systems were included in-scope for Criterion 2.

b. Internal/External Flooding

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 license renewal per 10 CFR 54.4(a)(2). If NSR sump pumps, piping and valves, are necessary to mitigate the effects of a flood which threatens SR SSCs intended functions, then these components are also within the scope of license renewal per 10 CFR 54.4(a)(2).

NSR walls, curbs, dikes, doors, etc., that provide flood barriers to protect SR SSCs, are within the scope of license renewal per 10 CFR 54.4(a)(2), and are typically included as part of the building structure, and evaluated in the civil/structural area review.

c. Internal/External Missiles

Missiles can be generated from internal or external events such as failure of rotating equipment or tornados. Inherent NSR features that protect safety related equipment from missiles are within the scope of license renewal per 10 CFR 54.4(a)(2). These protection features (missile barriers) are typically included as part of the building structure, and evaluated in the civil/structural area review.

d. Heavy Load Lifting Equipment

The overhead-handling systems from which a load drop could result in damage to any system that could prevent the accomplishment of a SR function, are considered to meet the criteria of 10 CFR 54.4(a)(2) and are within the scope of license renewal.

2) NSR SSCs Directly Connected to SR SSCs

For NSR SSCs directly connected to SR SSCs (typically piping systems), the NSR piping and supports, up to and including the first equivalent anchor beyond the safety/non-safety interface, are within the scope of license renewal per 10 CFR 54.4(a)(2). Although these piping segments are not uniquely identified on the LR boundary drawings, applicable aging effects on these piping segments are managed along with the adjoining SR piping.

3) NSR SSCs Not Directly Connected to SR SSCs

For NSR SSCs that are not directly connected to SR SSCs, or are connected downstream of the first equivalent anchor, the NSR SSCs may be in-scope if their failure could prevent the performance of the system safety function for which the SR SSC is required. To determine which NSR SSCs may be in-scope for 10 CFR 54.4(a)(2), two options exist: either a mitigative option or a preventive option.

a. Mitigative Option

An NRC reviewer provided additional guidance on the mitigative option in a recent RAI. In this context, “mitigative” means that the effects of failures of an NSR SSC are mitigated by other SSCs. This mitigation is such that the failure of the NSR SSC will not prevent the performance of a SR SSC's intended function identified in 10 CFR 54.4(a)(1). If the mitigative option is used, then the mitigative features (whip restraints, spray shields, supports, barriers, etc.) need to be included within the scope of license renewal per 10 CFR 54.4(a)(2), and the non-safety system can be excluded from the scope of license renewal. These mitigative features are typically associated with the structure, and would be addressed in the Civil/Structural area review.

b. Preventive Option

If mitigative features are not installed, or cannot be shown to adequately protect SR SSCs, then the preventive option needs to be used. The concern is that age-related degradation of NSR SSCs could lead to interactions with SR SSCs that have not been previously considered. These interactions (pipe whip, jet impingement, spray or flooding from the non-safety systems) could create additional failures of the SR SSCs. The following guidance for system/component applicability was used:

- Systems/Components Containing Air/Gas

  Components containing air/gas cannot adversely affect safety related SSCs due to leakage or spray. No industry or plant-specific OE has been identified where a failure due to aging of an air/gas system adversely impacted the accomplishment of a safety function. Therefore, these NSR air/gas systems are not considered to be in-scope for 10 CFR 54.4(a)(2).

- High-Energy Systems

  Non-safety high energy piping with a potential for spatial interaction (pipe whip, jet impingement, spray, or harsh environment) with vulnerable safety related equipment that is not protected from the effects of a failure of the high energy line, must be included within the scope of license renewal per 10 CFR 54.4(a)(2).

- Low/Moderate Energy Systems

  NSR moderate/low energy piping that has potential spatial interactions (spray or leakage) with vulnerable safety related equipment that is not protected from the effects of spray or leakage, must be included within the scope of license renewal per 10 CFR 54.4(a)(2).

- Piping Supports

  All NSR supports for non-seismic or Seismic II/I piping systems with a potential for spatial interaction with safety related SSCs, will be included within the scope of license renewal per 10 CFR 54.4(a)(2). These supports will be addressed in a commodity fashion, within the civil/structural area review.

As long as the effects of aging on the supports for these piping systems are managed, falling of piping sections, except for FAC failures, is not considered credible, and the piping section itself would NOT be in-scope for 10 CFR 54.4(a)(2) due to the physical impact hazard (although the leakage or spray hazard may still apply).

c. Methodology for Determining Mitigative or Preventive Components

1. Determine plant structures that house SR equipment.
2. Determine vulnerable SR equipment in the structures identified above. A SR SSC is considered “vulnerable” if there are NSR SSCs in the vicinity whose failure could prevent accomplishment of the SR SSC's safety function, with consideration for the following:

   - Exposure Duration

     Long term exposure to conditions resulting from a failed NSR SSC (such as leakage or spray) is not considered credible. The basis for this is that leakage/spray would be quickly identified by plant personnel via walkdowns, sump level trends, or system parameter monitoring and alarms, and once identified, appropriate corrective actions would be taken. Therefore, only NSR SSCs whose failure could result in a failure of an SR SSC due to a short-term exposure would need to be considered in-scope for 10 CFR 54.4(a)(2). For example, a short term exposure to spray or leakage from a failed NSR SSC onto an unprotected or unshielded SR motor or switchgear could prevent accomplishment of their SR intended functions, and therefore the NSR SSCs would be in-scope for 10 CFR 54.4(a)(2).

   - Components Qualified/Designed for Environment

     If an SR component is qualified/designed to maintain its function in an environment that could be caused by a failure of a nearby NSR SSC, that NSR SSC would not be considered to be within scope per 10 CFR 54.4(a)(2).

   - Plant-Specific Vulnerable Equipment

     For PBNP, the only vulnerable equipment that we have identified, is SR switchgear (along with associated controls, relays, fuses and instrumentation), SR batteries, SR pump motors, SR panels, and SR complex equipment (diesel generators). Other active SR equipment (transmitters, MOVs, SOVs, limit switches, I/P converters, enclosures, etc.) that is located in various operational areas of the plant, is designed to be spray proof, where a short duration spray will not affect the intended function of the SR components.

Some active SR equipment (i.e. relays, fuses, controls, etc) is housed within enclosures that are located in various operational areas of the plant (alternate power supplies, transfer switches). These enclosures are designed to be spray-proof also, and therefore the active equipment inside of them is not considered to be vulnerable. At PBNP, the enclosures that house SR equipment, are SR themselves, and are therefore already within the scope of LR. (Enclosures are addressed in the Civil/Structural area.) However, other panels (such as remote shutdown panels, local control stations, etc.) which have openings in enclosure doors (for lights, meter faces, or controls) are considered vulnerable.

Most of the active SR equipment that PBNP considers to not be vulnerable to spray or leakage, is not qualified (EQ) for harsh environments that could exist after a HELB. Therefore NSR high energy piping (that meets either high energy definition), that could create a harsh environment within a structure, will be included in scope. The only exception to this is in the turbine hall, where there are only a few SR components that could be exposed to a harsh environment, and these were addressed on a case-by-case basis.

3. Review documentation and/or perform walkdowns to identify non-safety systems or portions of systems that have spatial interaction potential with vulnerable equipment. Assume a failure anywhere along the length of the non-safety system.
4. Add these NSR systems/components identified above, to the scope of license renewal.

In summary, the components determined to be in-scope for Criterion 2 are listed in Table 2.1.2.1-1.

Table 2.1.2.1-1 Criterion 2 Scoping Results

Component Type(s)	Description	Drawing Reference	Reason	AMR Addressing Items
Cable, sensors, controls	Facade Freeze Protection components	None	Preventive	Electrical

Table 2.1.2.1-1 Criterion 2 Scoping Results

Component Type(s)	Description	Drawing Reference	Reason	AMR Addressing Items
Pipe, fittings, valve bodies, strainers,	SW return header piping	LR-M-207 Sh 1 LR-M-207 Sh. 2 LR-M-207 Sh. 3 LR-M-207 Sh. 4 LR-M-2207 Sh.1 LR-M-2207 Sh 2	Flooding, Preventive	Service Water
Ductwork, fans, dampers, controls	Control Room HVAC components to maintain CR envelope/habitabil -ity	LR-M-144 Sh 2	Preventive	Essential Ventilation
RE monitors, DAMs	Control Room Radiation monitors and DAMs, to maintain CR envelope /habitability	LR-M-144 Sh 2	Preventive	Electrical
Cranes, lifting devices	Various cranes and lifting devices that have QA Code 18	None	Heavy Loads	Structural
Supports	Various supports throughout the plant (piping, cable tray, conduit, panels, component, etc.)	None	Preventive, Mitigative	Structural
Breakers and Switchgear	Various breakers and switchgear in 125VDC and 120VAC systems	None	Preventive	Electrical

Table 2.1.2.1-1 Criterion 2 Scoping Results

Component Type(s)	Description	Drawing Reference	Reason	AMR Addressing Items
Walls, jet impingement shields, pipe whip supports, doors, dampers	Various structural components that provide either barriers to or vent paths for HELB.	None	HELB	Structural
Valve bodies, valve operators, piping, instrumenta-tion	Various components from various systems that were conservatively left in-scope based on QA codes	None	Preventive	Aux. Feedwater Safety Injection Main/Aux Steam Emergency Power
Missile barriers	Various structures that provide missile barriers	None	Missiles	Structural
Pipe, fittings, valve bodies, HXs	Heating Steam Supply and Condensate Returns in the PAB	LR-M-214 Sh. 1 LR-M-214 Sh. 2 LR-M-2214	Preventive (non-CLB HELB)	Heating Steam
Pipe, fittings, valve bodies	Aux. Steam sub-system downstream of SA-9 and SA-10, until piping exits PAB	LR-PBM-227	Preventive (non-CLB HELB)	Main and Auxiliary Steam
Pipe, fittings, valve bodies, HX	Letdown piping between CIV outside of containment and non-regen HX	LR-684J741 Sh 2 LR-685J175 Sh 2	Preventive (non-CLB HELB)	CVCS

Table 2.1.2.1-1 Criterion 2 Scoping Results

Component Type(s)	Description	Drawing Reference	Reason	AMR Addressing Items
Pipe, fittings, valve bodies	Main feedwater piping between reg./bypass valves and first check valve outside containment	LR-M-202 Sh 2 LR-M-2202 Sh 2	Preventive (non-CLB HELB)	Feedwater and Condensate
Pipe, fittings, valve bodies	Condensate return piping from SGBD HXs in mezzanine area (U1) and old water treatment area (U2)	LR-M-201 Sh 3 LR-M-2201 Sh 3	Preventive (non-CLB HELB)	Feedwater and Condensate
Fan unit, HX, instrumentation	RHR Area Cooler (W-67/HX-98) and SI/CS/CCW Pump Area cooler (W-68/HX-99) and actuating devices	LR-M-144 Sh 1	HELB	Essential Ventilation
Valve bodies	Shear gate valves in oily sump in G01 and G02 Rooms	LR-M-223 Sh 3	Flooding	Treated Water
Pipe, fittings, valve bodies	Equipment drains from HVAC Room above Control Room	None	Flooding	Treated Water
Pipe, fittings, valve bodies	Drain line and isolation valve from BDE bldg to Sump Tank	LR-684J971 Sh 1	Flooding	Waste Disposal

Table 2.1.2.1-1 Criterion 2 Scoping Results

Component Type(s)	Description	Drawing Reference	Reason	AMR Addressing Items
Valve bodies, level switches, annunciators	RHR cubicle drain valves and level switches, -19' Sump LS and annunciators	LR-684J971 Sh 1a	Flooding	Waste Disposal
Level switches, Annunciators	Sump level switches on PAB, TB, Facade sumps, and associated annunciators in Control Room	LR-M-223 Sh 3	Flooding	Treated Water
Pipe, fittings, valve bodies, pump casing, expansion joint	Circ water pump and discharge piping/valves/ expansion joints that are exposed in Circ water pumphouse	LR-M-212 Sh 1 LR-M-2212	Flooding	Circulating Water
Curbs, dikes, walls, penetration seals, doors, braces, pipe sleeves, subsoil drain covers, flood dampers	Various structural components throughout plant that provide flood barriers	None	Flooding	Structural
Pipe, fittings,	-19' Sump discharge piping through U2 RHR pump cubicle	LR-684J971 Sh 1a	Preventive	Waste Disposal

Table 2.1.2.1-1 Criterion 2 Scoping Results

Component Type(s)	Description	Drawing Reference	Reason	AMR Addressing Items
Pipe, fittings, valve bodies	Sump pump discharge piping in SI/CCW pump area; STP piping in CCW pump area	LR-M-223 Sh 3	Preventive	Treated Water
Pipe, fittings,	BS piping near 1&2B42	LR-685J175 Sh 2	Preventive	CVCS
Pipe, fittings,	RMW piping in proximity to 1B42, SI/Spray/CCW pumps, and outside of Charging pump cubicles	LR PBM-231 Sh 1	Preventive	CVCS
Shield walls, spray shields	Various structural components to protect 1B32 and Aux. Feedwater pumps	None	Mitigative	Structural
Pipe, fittings	CCW piping to Gas Stripper Bldg in proximity to 2B32	LR-PBM-230	Preventive	CCW
Pipe, fittings, valve bodies, strainer housings,	SW piping in Aux Feed pump room, (supply to U1/U2 non-essential loads)	LR-M-207 Sh 2 LR-M-2207 Sh 1	Preventive	Service Water
Pipe, fittings	MS piping from U2 SGBD in proximity to 2B32	LR-M-2201 Sh. 3	Preventive	Main and Auxiliary Steam

Table 2.1.2.1-1 Criterion 2 Scoping Results

Component Type(s)	Description	Drawing Reference	Reason	AMR Addressing Items
Pipe, fittings, valve bodies, pump casing	Screen wash sub-system from pumps until piping exits SW pump room	LR-M-212 Sh. 2	Preventive	Circulating Water
Pipe, fittings	Chlorination piping to SW pump pits in SW pump room	LR-PBM-232	Preventive	Circulating Water
Pipe, fittings, valve bodies	Spent Fuel Pool demin piping in proximity to SFP pumps	LR-110E018 Sh 4	Preventive	Spent Fuel
Pipe, fittings	Laundry/Hot Shower drain lines in proximity to SI and CCW pumps	LR-684J971 Sh 1	Preventive	Waste Disposal
Pipe, fittings, valve bodies	DI piping near spray pumps and SFP pumps, near pipeways #2 and #3 (8' el), and near U2 Charging pump cubicles	LR-PBM-231 Sh 2	Preventive	Treated Water
Pipe, fittings, valve bodies	WL piping to SW overboard, near CCW pumps, and in U2 hallway near pipeway #3 (8' el)	LR-684J971 Sh. 1	Preventive	Waste Disposal
Pipe, fittings, valve bodies	Fire protection piping in various areas	LR-M-208 Sh. 1 LR-M-208 Sh. 2 LR-M-208 Sh. 4 LR-M-208 Sh. 6 LR-M-208 Sh. 15	Preventive, but also in-scope for Criterion 3	Fire Protection

2.1.2.1.3 Other Scoping Pursuant to 10 CFR 54.4(a)(3) (Criterion 3)

The third scoping category in 10 CFR 54.4 involves SSCs relied upon by license renewal's five regulated events. Specifically, 10 CFR 54.4(a)(3) defines in-scope SSCs as those relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with one or more of the regulated events:

1) Fire Protection (10 CFR 50.48)

2) Environmental Qualification (10 CFR 50.49)

3) Pressurized Thermal Shock (10 CFR 50.61)

4) Anticipated Transients Without Scram (10 CFR 50.62)

5) Station Blackout (10 CFR 50.63)

Any system, structure, or component that meets one or more of these regulations is identified as a Criterion 3 component. All criterion 3 systems/components are considered to be in-scope of License Renewal.

Information was extracted from CHAMPS to identify any components as Category 3 by setting a flag in the LRDB, based on certain QA codes or CHAMPS flags. In addition to this, a separate review was performed on all five regulated events, to independently determine systems/structures/components that would be within the scope of License Renewal. The results of these reviews were incorporated into the LRDB.

A separate section is provided below for each of these regulations that describes the methodology used to determine any system, structure, or component that is required to support the regulations.

1) Fire Protection (FP)

Fire protection features and commitments are described in detail in the Fire Protection Evaluation Report (FPER). The FPER serves as PBNP’s fire plan as described in 10 CFR 50.48.

The design of the Point Beach Units 1 and 2 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 will be minimized. 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 Branch Technical Position APCSB 9.5-1 Appendix A and 10 CFR 50, Appendix R. The SSCs at Point Beach that support these multiple levels of protection are considered within the scope of license renewal.

Note that PBNP's scoping and screening process is consistent with the NRC Staff's guidance on consumables provided in NUREG-1800, Table 2.1-3. For fire protection this would include such items as fire extinguishers, fire hoses, portable lighting, and air packs (see Section 2.1.3.1.3).

Information sources which were used in performing this portion of the scoping effort were the Safe Shutdown Analysis Report (SSAR), Safe Shutdown Equipment List (SSEL contained in SSAR, Appendix A) and Fire Hazards Analysis Report (FHAR). These are further discussed below.

a. Safe Shutdown Analysis Report

Section III.G.1 of Appendix R to 10 CFR 50 requires that fire protection features be provided for systems, structures and components important to safe shutdown. In order to meet these requirements, all equipment required for safe shutdown, including the associated power and control cables, and any equipment which could adversely affect safe shutdown if spuriously actuated by fire-induced faults, have been identified for every fire area in the plant in order to assess the fire protection required. Safe shutdown is defined as hot standby conditions as a minimum, with the capability to proceed to cold shutdown should conditions warrant. Using this information, a Safe Shutdown Analysis was performed to determine the impact of a postulated fire on the safe shutdown equipment and circuitry within each fire area. Where a safe shutdown function was prevented, corrective actions (e.g., cable rerouting, cable protection, procedure changes, etc.) have been implemented to resolve the concern, or operator manual actions have been specified. In some cases credit is taken for equipment (other than the redundant counterpart) that provides a redundant function to the equipment affected by a postulated fire. Some examples include use of the pressurizer spray for Reactor Coolant System (RCS) pressure control when a fire affects both power-operated relief valves (PORVs) and use of the auxiliary feedwater (AFW) pump suction instrumentation for AFW process monitoring when a fire affects the condensate storage tank (CST) level instrumentation. This analysis ensured that no single fire could prevent Point Beach Units 1 and 2 from achieving a safe cold shutdown.

b. Safe Shutdown Equipment List

The first step of the safe shutdown analysis process was to establish the safe shutdown functions required to be performed. This was followed by selection of the systems, specific system equipment, and electrical/control circuits required to accomplish these functions. Process flow paths for each of the required systems were then traced on plant flow diagrams. Based on these system flow paths, a list of the minimum equipment necessary to bring the plant to cold shutdown was compiled. This list contains all power generation and distribution equipment (e.g., diesel generators, batteries, switchgear, motor control centers, power panels, etc.) that are required for the operation of the listed equipment. In addition, the list includes equipment that, although not required for safe shutdown, could adversely affect safe shutdown if spuriously actuated by a fire-induced electrical fault. This list is labeled the Appendix R Safe Shutdown Equipment List (SSEL).

c. Fire Hazards Analysis Report (FHAR)

A systematic approach was used for the review of the fire hazards and their exposure to safety related equipment and components necessary for safe shutdown within the area. The type and quantity of combustible materials, type of fire hazards these materials present in the area, and the fire protection features (passive, active and manual) for the area were reviewed. The effects of postulated fires on the performance of safe shutdown functions and the minimization of radioactive releases to the environment were evaluated for each fire area. These evaluations identify those portions of the plant Fire Protection System that are relied on to support the safe shutdown function of Appendix R.

Using the above described information sources, the components in the LRDB were reviewed to determine any which are required to support the fire protection function for License Renewal. The scoping of fire protection equipment meets the intent of the ISG on this subject (see Section 2.1.1.3.6).

Selected stored equipment required to reach and maintain cold shutdown under Appendix R are also considered in-scope under this criterion. See Section 2.1.3.1.1 for additional discussion.

2) Environmental Qualification (EQ)

The criteria for determining which equipment requires environmental qualification is defined by 10 CFR 50.49.

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 ensure -

(i) The integrity of the reactor coolant boundary,

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

(iii) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines in §50.34(a)(1), §50.67(b)(2), or §100.11 of Title 10 CFR.

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

c) Certain post-accident monitoring equipment (Refer to Regulatory Guide 1.97, Revision 2, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident”).

Electrical components, which meet these criteria for PBNP, are identified on the Environmental Qualification Master List (EQML) for 10 CFR 50.49. This list includes all equipment determined to be within the scope of 10 CFR 50.49. The equipment is listed by equipment tag number or by commodity group. Any newly installed electrical equipment that requires environmental qualification must be added to this list.

All electrical equipment identified on the EQML was verified as being identified as such in the EQ field of CHAMPS. The EQ field in CHAMPS was used to flag components in the LRDB that were in-scope for EQ. EQ is also a TLAA that is further discussed in Section 4.8.

3) Pressurized Thermal Shock (PTS)

PTS is a TLAA that is addressed in Section 4.2.1. The only component in license renewal scope for this criteria is the reactor vessel.

4) Anticipated Transients Without a Scram (ATWS)

PBNP’s system for mitigating ATWS events is described in detail in Section 7.4.1 of the Point Beach FSAR. The bounding event concerns a loss of feedwater without a unit trip (scram). If such an event is detected, the affected unit is automatically tripped and the Auxiliary Feedwater System is initiated. A QA code is used in CHAMPS to identify any components that support this event. All components associated with the ATWS QA code are in-scope for License Renewal.

5) Station Blackout (SBO)

PBNP's scoping effort for SBO was based on the NRC and industry guidance for achieving compliance with the SBO Rule as provided in NUMARC 8700 and NRC Regulatory Guide 1.155. FSAR Appendix A.1 provides the licensing criteria that comprise the CLB for PBNP for resolution of this issue. Point Beach's design satisfies the SBO Rule by providing for an Alternate AC source in the form of a separate on-site Gas Turbine Generator (GTG) capable of supplying either or both units. The GTG is capable of being started and loaded within one hour of the postulated SBO event. The GTG provides an adequate power supply for both units to maintain Hot Standby conditions. A QA code is used in CHAMPS to identify any components that support this event, which are not previously identified as safety-related or Augmented quality for Appendix R. All components associated with the SBO QA code are in-scope for license renewal.

The Interim Staff Guidance on SBO, issued by letter dated April 1, 2002 (Reference 9), was also used in the SBO scoping methodology and the SBO scoping results include the SSCs needed for restoration of offsite power following an SBO event. The following methodology was used in this scoping effort. Note that this scoping and screening effort had the objective to identify the first electrical interfacing equipment in the switchyard, under the control of the plant, which could provide a connection to offsite power following an SBO event.

Four sources of offsite power coming into the switchyard and the two circuit switchers that connect the switchyard bus to these power sources were identified. The bus sections, interconnections and switchgear that provided power paths back to the unit high-voltage station auxiliary transformers in the 13.8K VAC Power System were also identified. This provided connections to the in-scope 13.8K VAC Power System for each unit. The 13.8K VAC Power System has direct connection to the on-site gas turbine and provides one of the five sources of onsite Alternate AC (AAC) power for recovery from the SBO event. This process determined that the circuit switchers between the unit high-voltage station auxiliary transformers and the main switchyard bus were the boundary equipment meeting the ISG-02 criteria. These 345K VAC circuit switchers are the last components in this connection to offsite power controlled by the PBNP operators. This established the boundary for SBO scoping.

In order to conservatively ensure that these circuit switchers could be operated and that a source of offsite power could be routed through the switchyard to them, the switchyard electrical supervisory sub-system (SES), switches, instrumentation, batteries, chargers, inverters, cabinets, controls, and cables were also included, if needed to create these connections locally or from the control room to appropriate sections of the main switchyard bus. It is assumed that the transmission company, which controls this equipment, will be required to assure the plant of an offsite power source before any actions would be taken onsite to initiate any transfer from the AAC to offsite power.

This resulted in the inclusion of the Offsite Power System in the scope of license renewal and the extension of the 13.8K VAC Power System boundary to include the buses to the unit high-voltage station auxiliary transformers for each unit. Screening and aging management reviews were then completed, as appropriate.

In summary, the components determined to be in-scope for SBO are listed in Table 2.1.2.1.3-1.

Table 2.1.2.1.3-1 SBO Scoping Results

Component Type(s)	Description	Function	AMR Addressing Items
Cables and connections	Non-EQ insulated medium voltage, low voltage, and instrumentation cables	Power transmission, control power, and instrument signals	Electrical
Phase bus	Switchgear to transformer power connections	Power transmission	Electrical
High voltage insulators	Station post insulators	Support and electrical isolation	Electrical

Component Type(s)	Description	Function	AMR Addressing Items
Transmission conductors	Connections from electrical equipment to the switchyard bus	Power transmission	Electrical
Switchyard bus, connectors, and fittings	Equipment interconnections in the switchyard	Power and support	Electrical
Transformers	Station high-voltage auxiliary, current, and potential transformers	Power transmission and monitoring	Active - No AMR Required
Switchgear	Circuit breakers and circuit switchers	Switching and protection	Active - No AMR Required
Switches	Control and selector switches	Control, monitoring, and switching	Active - No AMR Required
Relays	Protection and control relays	Monitoring and protection	Active - No AMR Required
Batteries	Uninterruptible power source	Control power	Active - No AMR Required
Chargers	Battery charging	Control power	Active - No AMR Required
Inverters	DC to AC conversion	Control power	Active - No AMR Required
Panels	Support racks and control panels	Support and protection	Structural

Component Type(s)	Description	Function	AMR Addressing Items
Raceways	Conduit, trays, and cable trenches	Cable routing	Structural
Concrete foundations	Transformer, switchgear, and switchyard bus support	Support	Structural
Structural steel supports and fasteners	Switchyard bus support	Support	Structural

2.1.2.2 System/Structure Function Determination

The Scoping Process defined the entire plant in terms of major systems, structures, and commodity groups. System, structure, and commodity group system-level functions were identified and evaluated against criteria provided in 10 CFR 54.4(a)(1), (2), and (3), to determine whether the system, structure, or commodity should be considered in-scope for license renewal. Even if only a portion of a system, structure, or commodity fulfilled a scoping criterion, it was identified as in-scope for license renewal and received further evaluation.

The scoping methodology utilized by Point Beach is consistent with the guidance provided by the NRC in NUREG-1800, and by the industry in NEI 95-10. Existing plant documentation is used for this review including the Point Beach Current Licensing Basis documents, controlled drawings, and the CHAMPS database. Plant systems and components are sorted and tracked within CHAMPS using system identifiers. This identification scheme supports plant needs with respect to the maintenance work and, with additional information gleaned from the above referenced documentation, provides definition of license renewal system functional boundaries. LR systems account for and contain all of the CHAMPS systems (that contain permanently installed equipment) and do so in a manner that is consistent with the system descriptions in the FSAR. This information was entered into the PBNP License Renewal Data Base (LRDB).

PBNP system level function information was obtained from numerous sources that included the FSAR, docketed correspondence with the NRC, Maintenance Rule documents, and Design Basis Documents. This function information was used to create the system function list in the LRDB. Appropriate CLB references were added to each system function.

CHAMPS also contains a system for structures which consists of the site’s buildings/structures. The individual building/structures are listed as individual assets within this system, and as such, are part of the plant’s Q-list. Individual building/structures were input into the LRDB. The CHAMPS system, Containment Structures and Containment Penetrations, pertains to the containment building/structure and its components.

Commodity groups were formed when component evaluations were better performed by component type rather than by system or structure. Commodity groups were formed from components that were constructed from similar materials, exposed to similar environments, and performed similar intended functions regardless of the specific system or structure to which they are assigned. Commodity group components were not associated with a specific system or structure during the component's evaluation, but with the commodity group to which the component was assigned. Each commodity group was evaluated as if it was a separate, individual system.

To determine whether a system or structure was in-scope for license renewal, system-level functions were identified. If a system-level function met the criteria as specified in 10 CFR 54.4(a)(1), (2), or (3), then the system was considered in-scope.

One potential exception to this is when the only in-scope portion of the system consists of components that will receive a commodity group evaluation (e.g. fire barriers, equipment supports, etc.). In this case it is acceptable to identify the system or structure as not being within the scope of License Renewal, however the basis for that determination was clearly identified.

Example:The Non-Essential Ventilation System contains components that act as fire barriers (fire dampers). Within the system evaluation boundary, no other functions performed by the system are License Renewal IFs. Therefore, the system components that perform the fire barrier function were evaluated as part of the Fire Barrier Commodity Group and the Non-Essential Ventilation System was designated as not being within the scope of License Renewal.

The critical element of system scoping was to ensure that all SSCs that perform License Renewal IFs were identified and the criteria that made them in-scope for License Renewal was documented.

2.1.2.3 Boundary Evaluation

Application of all three 10 CFR 54.4 criteria generated a listing of SSCs that are considered in-scope for license renewal. Not every component of a system will support the system IFs, and therefore some components within a system or structure are not in-scope for license renewal. Where possible, these boundaries were depicted on drawings with color (magenta) over-lays to indicate those SSCs in-scope. The colored portions of the drawing are in-scope, and the black portions are not in-scope. (NOTE: Not all colored components shown on the boundary drawings are subject to an AMR.)

2.1.2.4 Mechanical System Specific Scoping

The mechanical discipline was responsible for scoping evaluations for the plant's mechanical piping systems. All of these systems contained some electrical and structural components. LR system boundaries were initially based on the associated CHAMPS system boundaries. CHAMPS component data was used with/compared to the Green Line Drawings to ensure that system boundaries and flow paths were accurately identified within the LRDB.

Some components within a system were moved to commodity groups, as applicable. For example, system pipe supports were moved to the Component Supports Commodity Group.

Electrical components were usually left in their respective systems, since the majority of them would be considered active. In some cases, these electrical components were used to identify passive, mechanical subcomponents (see below).

Within most systems, new assets or subcomponents were created within the LRDB, in order to ensure that all necessary assets/components could be accurately described and addressed within the LR process. Some of these decisions were based on knowing what would subsequently be needed for Screening or Aging Management Reviews. The following examples were used in the mechanical area:

- At PBNP, instrument manifolds, isolation, test, and vent valves, are not typically shown on P&IDs nor are they identified with individual EINs, beyond the root valves. For this reason, we created a “manifold” subcomponent for in-scope instruments. This “manifold” represents all tubing, valves, and manifolds that would be associated with that instrument.

- Bolting is not typically identified within a system, and therefore a new asset of “bolting” was created for each system. Bolting material types were not field verified, and therefore bolting assets for carbon/low alloy steel and stainless steel were created based on their potential to exist in each system.
- Heat exchangers were divided into subcomponents as necessary to identify all possible material/environment/intended function combinations (i.e. HX-tubing-ID for pressure boundary, HX-tubing-IDHT for heat transfer, HX-tubesheet if of a different material than the shell, etc.).
- Piping assets were created to identify all possible combinations of material/environment.
- “CS Components” asset was created for each system that had carbon steel components that could come into contact with leaking borated water, in order to manage boric acid wastage. This asset applies to any material types that may be susceptible to boric acid wastage.

All new subcomponents or assets were assigned an LR scoping criteria equal to their parent-asset's criteria.

In some instances, components were reviewed as part of another interfacing system in order to more accurately portray system functional boundaries or to streamline the overall LR process. In a few cases, all in-scope components for a single system could be reviewed as part of another interfacing system. These component review system designations are documented in the system descriptions.

A prime example of this is the Plant Sampling System. This system was populated in the LRDB with components from the CHAMPS sampling systems. Only a few of these components were determined to be in-scope. The majority of these in-scope components were from the three RCS sample lines, which are part of PBNP’s Class 1 piping boundary, and therefore all of these associated components were reviewed as part of the Class 1 Piping/Components System. The few remaining Plant Sampling System in-scope components were then reviewed along with associated interfacing systems (RHR sample line and valves in the RHR System, CVCS sample line and valves in the CVCS System, and CC-supplied heat exchangers in the CC System). This technique resulted in all the Plant Sampling System in-scope component reviews to be completed with interfacing systems. The Plant Sampling System will still be shown to be in-scope of LR, but the system description will describe the systems in which the component reviews have been completed.

2.1.2.5 Civil/Structural Specific Scoping

The systems, structures and commodity groups within License Renewal under the purview of the Civil/Structural discipline included all plant structures; the Cranes, Hoists, and Lifting Devices System; the Component Supports Commodity Group; and the Fire Barrier Commodity Group.

Information sources included the FSAR, CLB documentation, DBDs, training materials, CHAMPS database, drawings, specifications, codes/standards, design changes, plant procedures, and walkdowns of plant buildings.

Structures

Structures included site facilities such as buildings, foundations, roads, parking lots, manholes, and drainage structures. For PBNP structures, the license renewal database (LRDB) information was populated under the structure's CHAMPS noun name and abbreviation. Slight differences were incorporated into the license renewal database noun name or abbreviation, when the change clarified or simplified the license renewal database information.

The evaluation for a structure that was determined to be not in-scope for license renewal was documented in the license renewal database either individually by the structure's name or grouped under the Miscellaneous Non-Safety Related Buildings and Structures System. A structure's evaluation was individually documented when the structure's attributes, such as its functions or its location, warranted an in-depth explanation. A structure's evaluation was placed into the Misc. Non-Safety Related Buildings and Structures System when documentation of its evaluation was not extensive and did not need separate treatment within the LRDB. The Misc. Non-Safety Related Buildings and Structures System structure evaluations were similar, both in their content and their results/conclusions.

Commodity Groups

In certain situations it was beneficial to group similar component types, to permit dispositioning the entire group within a single aging management review. The basis for grouping the component types is founded on similar design and materials of construction considerations. The component's aging mechanisms and effects are independent of their systems. These commodity group components were represented generically by a limited number of material-environment generic assets. The two Civil/Structural discipline commodity groups include Component Supports and Fire Barriers.

The Component Supports Commodity Group includes component and equipment supports, fasteners and anchorages used with the support, pipe restraints, electrical raceways, and electrical enclosures. It excludes jet impingement barriers (HELB barriers), and miscellaneous plant structures and their details (e.g., stairs, platforms, crane rails), since they are evaluated with the structure that provides their support and/or shelter.

The Fire Barrier Commodity Group includes fire wraps, fire penetration seals, fire damper housings, and cable tray fire stops. Fire doors and structural walls that also serve as a fire barrier are not included with this commodity group, since they are evaluated with the structure.

Systems

The Cranes, Hoists, and Lifting Devices System is associated with the Civil/Structural discipline. It is a compilation of the load handling equipment that complies with NUREG-0612, where the potential for a heavy load drop could result in damage to safe shutdown equipment. The Containment Polar Cranes, the Auxiliary Building Main Crane, and the Turbine Building Main Crane are in this system. Fuel handling crane components are not within the scope of license renewal. All portions of the Fuel Handling System that were determined to be in-scope, have been moved to the Spent Fuel Cooling System, the Containment Unit 1/2 Building Structure, or the Primary Auxiliary Building Structure.

Evaluation Boundaries

Building evaluation boundaries, for the most part, were established at the building's column lines and/or physical barriers. Flexibility did exist in determining the exact location of a boundary between adjacent structures and was discussed in detail in the boundary description. Building appurtenances (i.e., doors) were included with the building. Commodity group evaluation boundaries were established by the nature of the component types that defined the commodity group.

Results

Refer to Table 2.2-1 for the listing of the Civil/Structural discipline in-scope and out-of-scope structures, systems, and commodity groups. The Miscellaneous Non-Safety Related Building and Structures System contains those SSCs that are not in-scope and that did not require extensive evaluation or documentation.

For Criterion 2, Non-Safety Related Affecting Safety Related, several other sources of information were reviewed to determine criterion applicability to the system, structure, or commodity being evaluated (i.e., HELB, flood, heavy loads, hazards-missiles, etc.).

The Criterion 3 is applicable to those building and/or structural assets that contribute directly to the support of the regulated event and are identified in the plant's CLB, safety analyses, or plant evaluations. Examples of direct reliance would be the walls, floors, and ceilings that are credited as fire barriers in the Fire Protection Evaluation Report or the Control Room/Cable Spreading Room structure that is credited as a heat sink during the Station Blackout coping period.

2.1.2.6 Electrical and I&C System Specific Scoping

The Electrical discipline was responsible for performing scoping evaluations on the plant's electrical and instrumentation and control (I&C) systems for their applicability to license renewal rule requirements. These systems are identified at specific voltage levels (e.g., 13.8K VAC, 480 VAC, 125 VDC, etc.) or within functional performance related systems (e.g., Radiation Monitoring, ESF Actuation, Reactor Protection, etc.) for electrical power or instrumentation and control, respectively.

The Scoping Process evaluations included an initial review of the system and component information to determine completeness of the system component list. Since some electrical components are contained in generic systems (e.g., Metering and Relaying) in the CHAMPS database, these components needed to be identified and transferred within the LRDB into their specific electrical systems.

During the Scoping Process, an evaluation boundary was established for each system or commodity group in order to identify the functions associated with the system or commodity being evaluated. Each system, with which the system being evaluated was interfacing, was defined and the interfacing equipment was identified at the component level. For power cables to equipment (e.g., motors, valves, etc.) the system interfaces are assumed at the protective device (breaker or fuse) and the cable associated with the equipment. For interfaces between systems at different voltage levels, the interconnecting transformers were the interface and they were included in the system as identified in CHAMPS and the system drawings. This was necessary in order to assure that the appropriate scoping criteria and all system-level functions were identified. For commodities, the types of components that defined the commodity were determined to identify their appropriate scoping criteria and system-level functions. While junction boxes, panels, and cabinets in the PANEL commodity and electrical penetration assemblies in the EPA commodity are identified in the CHAMPS equipment database, the individual cables for the CABLE commodities are not. Cables are tracked using the Cable and Raceway Data System (CARDS).

The boundaries for the in-scope systems were defined to accurately determine the components that would need screening. Information regarding the systems and commodities was identified from review of the FSAR, CHAMPS, CLB documentation, DBDs, plant databases and documents, procedures, drawings, specifications, codes/standards, and system walkdowns.

2.1.3 Screening Methodology

10 CFR 54 provides specific criteria for identifying structures and components subject to an aging management review. Specifically 10 CFR 54.21 of the Rule states:

(1) For those systems, structures, and components within the scope of this part, as delineated in 10 CFR 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 10 CFR 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.

The Scoping process (as discussed in Section 2.1.2) identifies which structures and components are in-scope for license renewal. The screening process evaluates these in-scope structures and components to determine which ones are long-lived and passive, and therefore subject to an aging management review.

2.1.3.1 Active/Passive Determination

All in-scope structures and components were evaluated to determine if they performed their intended function without moving parts or change in configuration or properties. The determination of active or passive for each structure and component was recorded in the LRDB.

- All structural components within the evaluation boundaries, with the exception of snubbers, are assumed to be long-lived and passive, and thus are subject to aging management review.
- Appendix B to NEI 95-10, which contains a list of component types and indicates whether they are generally considered to be passive or active. For the mechanical and electrical components that are in-scope, Appendix B of NEI 95-10 was used to determine which components function with moving parts or with a change in configuration or properties (i.e. active components).
  1. All instruments are considered active unless they form an integral part of the pressure-retaining boundary, such as level glasses, flow glasses, and in-line flow switches.
  2. Fans and dampers are normally considered active components, but per the ISG (see Section 2.1.1.3.5), fan and damper housings were considered passive and subject to an AMR.
  3. Temperature elements (TE) are typically active components per NEI 9510, however, since PBNP does not typically identify thermowells in CHAMPS, the TE components were marked passive, in order to represent the pressure boundary function (either the thermowell or other fittings if it was a direct immersion TE).
  4. Solenoid valves (SOVs) are also typically active components. However, in some cases, the solenoid valve body will actually need to perform a pressure boundary function. All SOVs were carefully reviewed against this criteria, and those that needed to maintain a pressure boundary were marked passive.
- Components subject to replacement based on a qualified life or specified time period (i.e. not long-lived components) are not subject to AMR, per the Rule. This caveat was seldom used at PBNP, but when it was, justification (callup or other work control mechanism that ensures routine replacement) was provided for using this option.

2.1.3.1.1 **Screening of Stored Equipment**

In response to the NRC letter from Chris Grimes to Doug Walters (NEI) dated February 11, 1999, Subject: Screening of Equipment Kept in Storage (Reference 5), a review has been performed to identify equipment that (1) is maintained in storage, (2) is reserved for installation in the plant in response to a design basis event (DBE), and (3) requires an AMR. In addition to passive components, the review has also considered stored active components that are not routinely inspected, tested, and maintained.

The Appendix R stored equipment is used to restore power to pre-selected plant components and to provide cooling to certain areas after a fire in order to attain cold shutdown. The stored equipment identified as requiring an aging management review is cable and connectors.

2.1.3.1.2 **Screening of Thermal Insulation**

In response to NRC staff requests for additional information (RAI) on other license renewal applications, a screening review has been performed of thermal insulation. The review identified only one location where thermal insulation is within the scope of License Renewal. Insulation is installed on the main steam and main feedwater Containment penetrations, and is needed to maintain steady-state concrete temperatures less than 150 degrees F. This insulation is enclosed in the annulus and is not subject to wetting, and there are no plausible aging effects that could warrant aging management.

2.1.3.1.3 **Identification of Short-lived Components and Consumables**

The screening process has attempted to identify those components that can be treated as short-lived. If a work control document was found to provide for the periodic replacement of the component, or the component was found to have an established qualified life (e.g., for EQ purposes), the component has been identified as short-lived and an aging management review is not required for that component.

Consumables are a special class of short-lived items that can include packing, gaskets, component seals, O-rings, oil, grease, component filters, system filters, fire extinguishers, fire hoses, and air packs. Many types of consumables are part of a component such as a valve or a pump and, therefore, have not been identified during screening. Items potentially treatable as consumables have been evaluated consistent with the information presented in Table 2.1-3 of Reference 6. The results of that evaluation are presented below.

Packing, Gaskets, Component Seals, and O-Rings

Packing, gaskets, component mechanical seals, and O-rings are typically used to provide a leak-proof seal when components are mechanically joined together. These items are commonly found in components such as valves, pumps, heat exchangers, ventilation units/ducts, and piping segments. These types of consumables are considered subcomponents of the identified components and, therefore, are not subject to their own condition or performance monitoring. Therefore, the AMR for the component has included an evaluation of the sealing materials in those instances where it could not be demonstrated that one of the following conditions exist:

1. The sealing materials are short-lived because they are replaced on a fixed frequency or have a qualified life established (e.g., for EQ purposes), or
2. The sealing materials are not relied on in the CLB to maintain any of the following:
    - Leakage below established limits
    - System pressure high enough to deliver specified flow rates
    - A pressure envelope for a space

Note: Sealants used to provide flood and fire barriers are addressed in Section 2.1.2.5.

Oil, Grease, and Filters

Oil, grease, and filters (both system and component filters) have been treated as consumables because either:

1. A program for periodic replacement exists, or
2. A monitoring program (e.g., predictive analysis activities, condition monitoring) exists that replaces these consumables, based on established performance criteria, when their condition begins to degrade but before there is a loss of intended function.

Fire Extinguishers, Fire Hoses, and Air Packs

Components such as fire hoses, fire extinguishers, self-contained breathing apparatus (SCBA), and SCBA cylinders are considered to be consumables and are routinely tested or inspected. The Fire Protection Program complies with the applicable NFPA safety standards, which specify performance and condition monitoring programs for these specific components. Fire hoses and fire extinguishers are inspected and hydrostatically tested periodically and must be replaced if they do not pass the test or inspection. SCBA and SCBA cylinders are inspected and periodically tested and must be replaced if they do not pass the test or inspection. The Fire Protection Program determines the replacement criterion of these components that are routinely checked by tests or inspections to assure operability. Therefore, while these consumables are in the scope of license renewal, they do not require an AMR.

2.1.3.2 Identification of Component Intended Function

Component intended functions are functions that individual components have to perform in order for the system intended function to be maintained. Intended functions for each of the passive, long-lived structures/components were documented in the LRDB, since only these components would be subject to AMR.

- NEI 95-10 provided a list of typical structure and component intended functions, which was referenced when assigning intended functions for mechanical, electrical, and structural components types.
- Components may have more than one intended function. All intended functions were considered. If a component intended function could not be identified for a component, then it was not subject to AMR. A component that is subject to AMR must have at least one intended function.

Section 2.1 References

1. Regulatory Guide 1.97, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident.
2. NEI 95-10, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 -The License Renewal Rule, Rev. 4 Draft, Nuclear Energy Institute.
3. Branch Technical Position (BTP) APCSB 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Power Plants August 23, 1976.
4. Letter of August 5, 1999 from Christopher I. Grimes of the NRC to Douglas J. Walters of NEI, Subject: License Renewal Issue No. 98-0082, Scoping Guidance.
5. Letter of February 11, 1999 from Christopher I. Grimes of the NRC to Doug Walters of NEI, Subject: Request for Additional Information Regarding Generic License Renewal Issue No. 98-0102, Screening of Equipment that is Kept in Storage.
6. Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, NUREG-1800, U.S. Nuclear Regulatory Commission, July 2001.
7. Letter of December 3, 2001 from Christopher I. Grimes of the NRC to Alan Nelson of NEI, Subject: License Renewal Issue: Scoping of Seismic II/I Piping Systems.
8. Letter of March 10, 2003 from David B. Matthews of the NRC to Alan Nelson of NEI, Subject: Interim Staff Guidance (ISG) - 5 on the Identification and Treatment of Electrical Fuse Holders for License Renewal.
9. Letter of April 1, 2002 from David B. Matthews of the NRC to Alan Nelson of NEI, Subject: 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)).

Table 2.1-1 System Function Codes

System Function Code	Function Description	Notes	10 CFR 54.4(a) Criterion
A	MAINTAIN REACTOR CORE ASSEMBLY GEOMETRY		1
B	INTRODUCE EMERGENCY NEGATIVE REACTIVITY TO MAKE THE REACTOR SUBCRITICAL	Functions include limiting the introduction of positive reactivity.	1
C	INTRODUCE NEGATIVE REACTIVITY TO ACHIEVE OR MAINTAIN SUBCRITICAL REACTOR CONDITION		1
D	SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION		1
E	PROVIDE REACTOR COOLANT PRESSURE BOUNDARY		1
F	REMOVE RESIDUAL HEAT FROM THE RCS	Residual heat removal by direct recirculation of reactor coolant. This system function does not address emergency core cooling via Engineered Safety Features Actuation.	1
G	PROVIDE EMERGENCY CORE COOLANT WHERE THE ECCS PROVIDES COOLANT DIRECTLY TO THE CORE	This function includes coolant that is provided to the core via RCS piping. This function also addresses coolant inventory that is maintained for use by the ECCS to provide emergency core cooling and to introduce negative reactivity.	1
H	PROVIDE EMERGENCY HEAT REMOVAL FROM THE REACTOR COOLANT SYSTEM USING SECONDARY HEAT REMOVAL CAPABILITY	Secondary heat removal capability addresses the secondary side of the steam generators, and steam generator secondary cooling paths, for example: Auxiliary Feedwater, Relief Valves/Lines.	1

Table 2.1-1 System Function Codes

System Function Code	Function Description	Notes	10 CFR 54.4(a) Criterion
J	PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	This function addresses heat removal as necessary to provide a nuclear safety function. This function does not include emergency heat removal from the secondary side of the Steam Generators (System Function H).	1
K	PROVIDE PRIMARY CONTAINMENT BOUNDARY	This function addresses any primary containment fission product barrier or primary containment radioactive material holdup or isolation.	1
L	PROVIDE EMERGENCY HEAT REMOVAL FROM PRIMARY CONTAINMENT AND PROVIDE CONTAINMENT PRESSURE CONTROL		1
M	PROVIDE EMERGENCY REMOVAL OF RADIOACTIVE MATERIAL FROM THE PRIMARY CONTAINMENT ATMOSPHERE		1
N	CONTROL COMBUSTIBLE GAS MIXTURES IN THE PRIMARY CONTAINMENT ATMOSPHERE		1
O	MAINTAIN EMERGENCY TEMPERATURES WITHIN AREAS CONTAINING SAFETY CLASS 1, 2, 3 COMPONENTS		1
P	ENSURE ADEQUATE COOLING IN THE SPENT FUEL POOL	Cooling to maintain stored fuel within acceptable temperature limits.	1
Q	PROVIDE ELECTRICAL POWER TO SAFETY CLASS 1, 2, 3 COMPONENTS		1

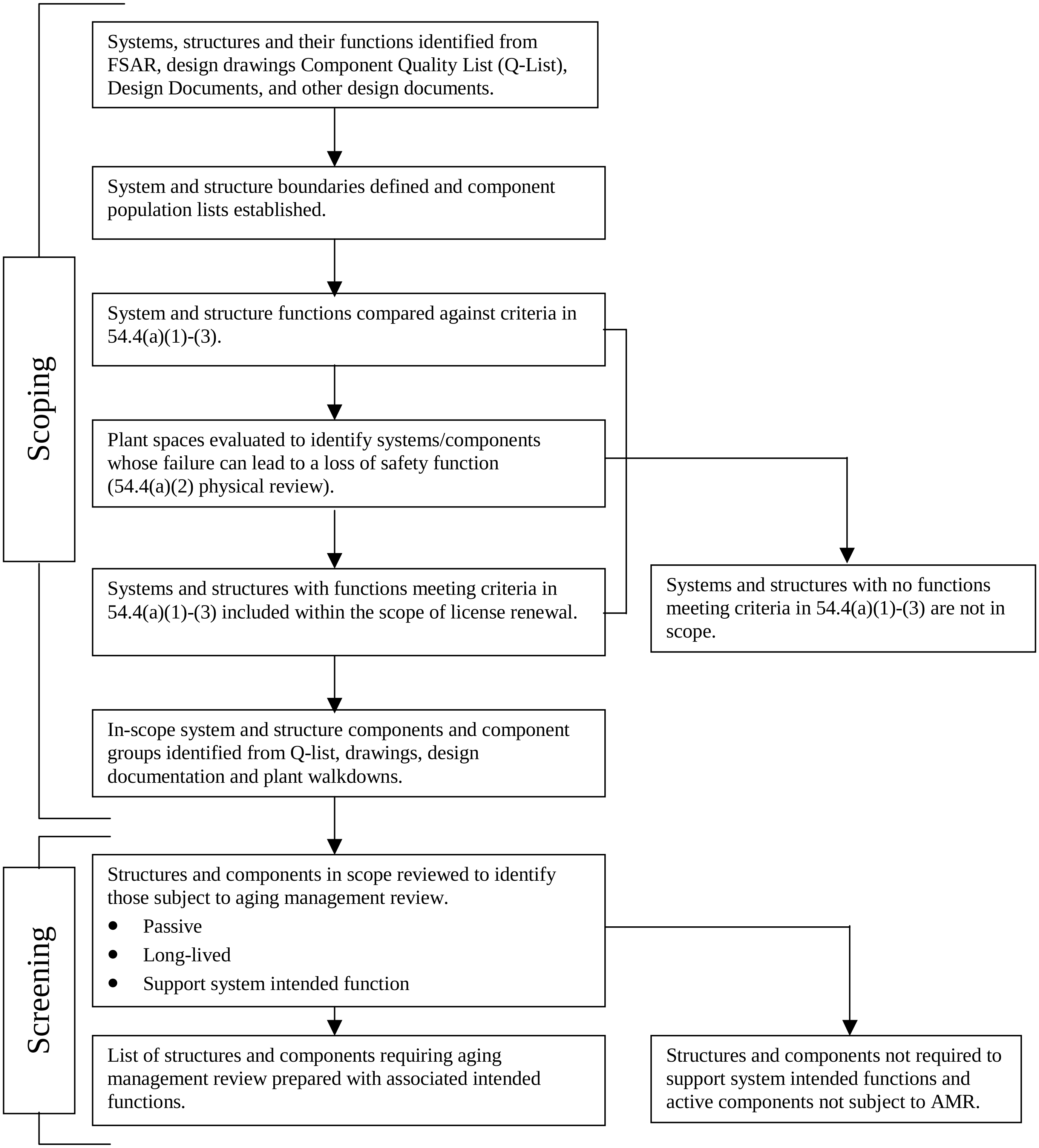
Table 2.1-1 System Function Codes

System Function Code	Function Description	Notes	10 CFR 54.4(a) Criterion
R	STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS		1
S	SPECIAL CAPABILITY CLASS FUNCTIONS	Components within the system are Augmented Quality, but they are not within the scope of license renewal (typically Regulatory Guide 1.97 B, C, D and E variables).	Not In-Scope
T	NON-NUCLEAR SAFETY CLASS FUNCTIONS	Non-LR functions	Not In-Scope
U	PROVIDE ELECTRICAL CONNECTIONS TO SPECIFIC SECTIONS OF AN ELECTRICAL CIRCUIT TO DELIVER VOLTAGE, CURRENT OR SIGNALS		1, 3
V	INSULATE AND SUPPORT ELECTRICAL CONDUCTOR		1, 2, 3
X	FUNCTION APPLICABLE AT COMPONENT LEVEL	Regulatory Guide 1.97 A variables	1
Y	LICENSE RENEWAL CRITERION 2 - NON-SAFETY RELATED SSCs WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION		2
Z1	LICENSE RENEWAL CRITERION 3 - SSCs RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)		3

Table 2.1-1 System Function Codes

System Function Code	Function Description	Notes	10 CFR 54.4(a) Criterion
Z2	LICENSE RENEWAL CRITERION 3 - SSCs RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)		3
Z3	LICENSE RENEWAL CRITERION 3 - SSCs RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR PRESSURIZED THERMAL SHOCK (10 CFR 50.61)		3
Z4	LICENSE RENEWAL CRITERION 3 - SSCs RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ANTICIPATED TRANSIENTS WITHOUT SCRAM (10 CFR 50.62)		3
Z5	LICENSE RENEWAL CRITERION 3 - SSCs 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)		3

Figure 2.1-1 Scoping and Screening Process Overview



2.2 Plant Level Scoping Results

The systems, structures, and commodities at Point Beach were evaluated as to whether they were within the scope of license renewal, using the methodology described in Section 2.1. The results are shown in Table 2.2-1.

2.2.1 Intended Function Code Definitions

This section contains the meanings for the abbreviations used in the Scoping/Screening results tables to represent the intended functions for components, subcomponents, and structural members. Intended functions are the specific intended functions performed by in-scope passive components in support of system or structure intended functions. Passive components are components that perform an intended function without moving parts or without a change in configuration or properties.

CODE	DEFINITION
MECHANICAL	
FLOW CONTROL	PROVIDE FLOW CONTROL OR DISTRIBUTION, AS THROUGH A SPRAY NOZZLE
FLOW DISTRIBUTION	PROVIDE A PASSAGEWAY FOR THE DISTRIBUTION OF THE REACTOR COOLANT FLOW TO THE REACTOR CORE
GAMMA/NEUTRON SHIELDING	PROVIDE GAMMA AND NEUTRON SHIELDING FOR THE REACTOR PRESSURE VESSEL. (VESSEL INTERNALS ONLY)
HEAT TRANSFER	PROVIDE HEAT TRANSFER
MECHANICAL CLOSURE INTEGRITY	PROVIDE MECHANICAL CLOSURE INTEGRITY ON BOLTED JOINTS
PRESSURE BOUNDARY	PROVIDE PRESSURE-RETAINING BOUNDARY SO THAT SUFFICIENT FLOW AT ADEQUATE PRESSURE IS DELIVERED
PROVIDE FILTRATION	PROVIDE FILTRATION
PROVIDE SUPPORT	PROVIDE STRUCTURAL SUPPORT TO SAFETY RELATED COMPONENTS

CODE	DEFINITION
RESTRICT FLOW (THROTTLING)	PROVIDE FLOW RESTRICTION (THROTTLE)
SECONDARY CORE SUPPORT	PROVIDE A SECONDARY CORE SUPPORT FOR LIMITING THE CORE SUPPORT STRUCTURE DOWNWARD DISPLACEMENT (VESSEL INTERNALS ONLY)
SUPPORT CORE	PROVIDE SUPPORT AND ORIENTATION OF THE REACTOR CORE (VESSEL INTERNALS ONLY)
SUPPORT IN-CORE INSTRUMENTATION	PROVIDE A PASSAGEWAY FOR SUPPORT, GUIDANCE, AND PROTECTION FOR IN-CORE INSTRUMENTATION (VESSEL INTERNALS ONLY)
SUPPORT RCCAS	PROVIDE SUPPORT, ORIENTATION, GUIDANCE, AND PROTECTION OF THE CONTROL ROD ASSEMBLIES (VESSEL INTERNALS ONLY)
ELECTRICAL	
DELIVER VOLTAGE, CURRENT, OR SIGNAL	TO ELECTRICALLY CONNECT SPECIFIED SECTIONS OF AN ELECTRICAL CIRCUIT TO DELIVER VOLTAGE, CURRENT, OR SIGNAL
ELECTRICALLY ISOLATE AND SUPPORT	TO ELECTRICALLY ISOLATE AND PROVIDE STRUCTURAL SUPPORT TO TRANSMISSION CONDUCTORS AND SWITCHYARD BUSES
ELECTRICALLY ISOLATE AND SUPPORT	TO ELECTRICALLY ISOLATE AND PROVIDE STRUCTURAL SUPPORT TO PHASE BUS
STRUCTURAL	
DIRECT FLOW	PROVIDE SPRAY SHIELD OR CURBS FOR DIRECTING FLOW (E.G., SAFETY INJECTION FLOW TO CONTAINMENT SUMP)

CODE	DEFINITION
FIRE BARRIER	PROVIDE RATED FIRE BARRIER TO CONFINE OR RETARD A FIRE FROM SPREADING TO OR FROM ADJACENT AREAS OF THE PLANT
FLOOD BARRIER	PROVIDE FLOOD PROTECTION BARRIER (INTERNAL AND EXTERNAL FLOODING EVENT)
HEAT SINK	PROVIDE HEAT SINK DURING SBO OR DESIGN BASIS ACCIDENTS
HELB SHIELDING	PROVIDE SHIELDING AGAINST HIGH ENERGY LINE BREAKS
MAINTAIN SUBCRITICALITY	MAINTAIN SUBCRITICALITY OF SPENT FUEL
MISSILE BARRIER	PROVIDE MISSILE BARRIER (INTERNALLY OR EXTERNALLY GENERATED)
PIPE WHIP RESTRAINT	PROVIDE PIPE WHIP RESTRAINT
PRESSURE BOUNDARY	PROVIDE PRESSURE BOUNDARY OR ESSENTIALLY LEAK TIGHT BARRIER TO PROTECT PUBLIC HEALTH AND SAFETY IN THE EVENT OF ANY POSTULATED DESIGN BASIS EVENTS.
RADIATION SHIELDING	PROVIDE SHIELDING AGAINST RADIATION
SHELTER SR	PROVIDE SHELTER/PROTECTION TO SAFETY RELATED COMPONENTS
SUPPORT NSR	PROVIDE STRUCTURAL SUPPORT TO NON-SAFETY RELATED COMPONENTS WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF ANY OF THE REQUIRED SAFETY RELATED FUNCTIONS OR REGULATED EVENT FUNCTIONS

CODE	DEFINITION
SUPPORT SR	PROVIDE STRUCTURAL AND/OR FUNCTIONAL SUPPORT TO SAFETY RELATED EQUIPMENT
WATER SOURCE	PROVIDE SOURCE OF COOLING WATER FOR PLANT SHUTDOWN

Table 2.2-1 Plant Level Scoping Results

Description	Within Scope of License Renewal?	Comments
SRP Evaluation Group: Reactor Vessel, Internals, and Reactor Coolant System		
Class 1 Piping/Components (Section 2.3.1.1)	Yes	This system spans numerous systems including portions of Safety Injection, Residual Heat Removal, Chemical and Volume Control, and Plant Sampling.
Reactor Vessel (Section 2.3.1.2)	Yes	
Reactor Vessel Internals (Section 2.3.1.3)	Yes	
Pressurizer (Section 2.3.1.4)	Yes	
Steam Generators (Section 2.3.1.5)	Yes	
Non-Class 1 RCS Components (Section 2.3.1.6)	Yes	RCP oil collection equipment is addressed in the Fire Protection System.
SRP Evaluation Group: Engineered Safety Features		
Containment Isolation Components (Section 2.3.2.4)	Yes	This system includes Containment isolation components from the Radiation Monitoring, Heating Steam, and Treated Water Systems, and mechanical portions of miscellaneous Containment penetrations
Containment Spray (Section 2.3.2.2)	Yes	
Residual Heat Removal (Section 2.3.2.3)	Yes	This system includes some Plant Sampling System components. The Class 1 portions of this system are addressed in the Class 1 Piping/ Components System.
Safety Injection (Section 2.3.2.1)	Yes	The Class 1 portions of this system are addressed in the Class 1 Piping/Components System.

Table 2.2-1 Plant Level Scoping Results

Description	Within Scope of License Renewal?	Comments
SRP Evaluation Group: Auxiliary Systems		
Chemical and Volume Control (Section 2.3.3.1)	Yes	This system includes some Plant Sampling System components. The Class 1 portions of this system are addressed in the Class 1 Piping/ Components System.
Circulating Water (Section 2.3.3.12)	Yes	Portions of this system were added to the License Renewal scope for Criterion 2 only.
Component Cooling Water (Section 2.3.3.2)	Yes	This system includes some Plant Sampling System components.
Containment Ventilation (Section 2.3.3.9)	Yes	
Containment Hydrogen Detectors and Recombiner (Section 2.3.3.16)	Yes	
Dry Fuel Storage	No	Dry Fuel Storage Systems do not fall under the requirements of 10 CFR 54 and are managed under 10 CFR 72.
Essential Ventilation (Section 2.3.3.10)	Yes	This system includes the Chilled Water sub-system.
Emergency Power (Section 2.3.3.8)	Yes	This system includes the Diesel Generators and Gas Turbine and their Air, Lube Oil, and Fuel Oil Support sub-systems.
Fire Protection (Section 2.3.3.6)	Yes	This system includes the RCP oil collection equipment. Fire rated assemblies are included with the structures in the Fire Barrier Commodity Group.
Fuel Handling (Section 2.3.3.13)	Yes	In-scope components are addressed in the Primary Auxiliary Building Structure, the Containment Unit 1/2 Building Structure, and the Spent Fuel Cooling System.

Table 2.2-1 Plant Level Scoping Results

Description	Within Scope of License Renewal?	Comments
Heating Steam (Section 2.3.3.7)	Yes	Portions of this system were added to the License Renewal scope for Criterion 2 only.
Miscellaneous Ventilation	No	Fire Dampers are included in the Fire Barrier Commodity Group.
Non-Essential Ventilation	No	Fire Dampers are included in the Fire Barrier Commodity Group.
Plant Air (Section 2.3.3.15)	Yes	Some air sub-systems for continued functionality after loss of air, are included within their associated system (Containment Ventilation, Main and Auxiliary Steam, Auxiliary Feedwater)
Plant Sampling (Section 2.3.3.14)	Yes	Plant Sampling components are addressed in the Class 1 Piping/Components System, or other associated systems (Residual Heat Removal, Chemical and Volume Control, or Component Cooling Water).
Service Water (Section 2.3.3.5)	Yes	
Spent Fuel Cooling (Section 2.3.3.3)	Yes	This system includes some Fuel Handling System components.
Treated Water (Section 2.3.3.11)	Yes	Portions of this system were added to the License Renewal scope for Criterion 2 only. Containment isolation components for the Demineralized Water sub-system are in the Containment Isolation Components System.
Waste Disposal (Section 2.3.3.4)	Yes	
SRP Evaluation Group: Steam and Power Conversion System		
Auxiliary Feedwater (Section 2.3.4.3)	Yes	
Feedwater and Condensate (Section 2.3.4.2)	Yes	

Table 2.2-1 Plant Level Scoping Results

Description	Within Scope of License Renewal?	Comments
Main and Auxiliary Steam (Section 2.3.4.1)	Yes	
Turbine-Generator and Supporting Systems	No	
SRP Evaluation Group: Containments, Structures and Component Supports		
13.8 KV Switchgear Building Structure (Section 2.4.12)	Yes	
Blowdown Evaporator Building Structure	No	
Circulating Water Pumphouse Structure (Section 2.4.3)	Yes	
Component Supports Commodity Group (Section 2.4.10)	Yes	This group Includes electrical panels, cabinets, junction boxes, pipe supports, cable tray supports, and conduit supports.
Containment Unit 1/2 Building Structure (Section 2.4.1)	Yes	This structure includes some Fuel Handling System components.
Control Building Structure (Section 2.4.2)	Yes	
Cranes, Hoists, and Lifting Devices (Section 2.4.9)	Yes	
Diesel Generator Building Structure (Section 2.4.4)	Yes	
Facade Unit 1/2 Structure (Section 2.4.5)	Yes	
Fire Barrier Commodity Group (Section 2.4.11)	Yes	This group includes fire wraps, fire penetrations, seals, fire damper housings, and cable tray fire stops.

Table 2.2-1 Plant Level Scoping Results

Description	Within Scope of License Renewal?	Comments
Fuel Oil Pumphouse Structure (Section 2.4.13)	Yes	
Gas Turbine Building Structure (Section 2.4.14)	Yes	
Letdown Gas Stripper Building Structure	No	
Misc. Non-Safety Related Buildings and Structures	No	
Primary Auxiliary Building Structure (Section 2.4.6)	Yes	This structure includes some Fuel Handling System components.
Technical Support Center Structure	No	
Turbine Building Unit 1/2 Structure (Section 2.4.7)	Yes	
Yard Structures (Section 2.4.8)	Yes	
SRP Evaluation Group: Electrical and Instrumentation and Controls		
120 VAC Vital Instrument Power (Section 2.5.2)	Yes	
125 VDC Power (Section 2.5.3)	Yes	
480 VAC Power (Section 2.5.5)	Yes	
4160 VAC Power (Section 2.5.4)	Yes	
13.8K VAC Power (Section 2.5.12)	Yes	

Table 2.2-1 Plant Level Scoping Results

Description	Within Scope of License Renewal?	Comments
Control Board Annunciators	No	Annunciator cabinets and mountings are evaluated under the Component Supports Commodity Group.
Control Rod Drive and Indication and Nuclear Process Instrumentation System (Section 2.5.6)	Yes	
Engineered Safety Features Actuation (Section 2.5.10)	Yes	
Miscellaneous AC Power and Lighting (Section 2.5.7)	Yes	
Offsite Power (Section 2.5.8)	Yes	In-scope for restoration of offsite power following an SBO event. Some metering, relaying, and regulation components were placed in their respective systems by voltage level.
Plant Communications (Section 2.5.11)	Yes	
Plant Process Computers	No	
Plant Security	No	
Radiation Monitoring (Section 2.5.13)	Yes	Pressure boundary components from this system are addressed in the Component Cooling Water, Essential Ventilation, and Service Water Systems. Portions of this system that are part of the Containment boundary are addressed in the Containment Isolation Components System.
Reactor Protection (Section 2.5.9)	Yes	This system includes ATWS components.
Seismic and Meteorological Instrumentation	No	

2.3 Scoping and Screening Results: Mechanical Systems

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

The following systems are addressed in this section:

- Class 1 Piping/Components System (Section 2.3.1.1)
- Reactor Vessel (Section 2.3.1.2)
- Reactor Vessel Internals (Section 2.3.1.3)
- Pressurizer (Section 2.3.1.4)
- Steam Generators (Section 2.3.1.5)
- Non-Class 1 RCS Components System (Section 2.3.1.6)

2.3.1.1 Class 1 Piping/Components System

System Description

The Class 1 Piping/Components System consists of the main RCS loops, and interconnecting piping from various other systems, typically out to the second isolation valve off of the main RCS loop. The RCS consists of two heat transfer loops connected in parallel to the Reactor Pressure Vessel (RPV). Each reactor coolant loop contains a reactor coolant pump (RCP) and steam generator (SG). In addition, the RCS includes a pressurizer (connected to Loop B hot leg), interconnecting piping and valves, and instrumentation necessary for protection and control.

The Reactor Pressure Vessel (RPV) (Section 2.3.1.2), RPV internals (Section 2.3.1.3), Steam Generators (Section 2.3.1.5), Pressurizer (Section 2.3.1.4), and supports for the RCS piping and components (Section 2.4.10) are addressed separately. The regenerative and excess letdown heat exchangers (Class 1 components) are addressed in the Chemical and Volume Control System (Section 2.3.3.1). The Class 1 Piping/Components System boundaries typically include branch piping and root isolation valves for various instruments. Instrument piping, tubing, valve manifolds, and instruments are addressed in the Non-Class 1 RCS Components System (Section 2.3.1.6).

The Class 1 Piping/Components System boundaries start with and include circumferential welds joining the piping to associated major component nozzles. The nozzle and safe ends are evaluated in the section for the respective major component (e.g. the Pressurizer nozzles and safe end are evaluated with the Pressurizer).

The Class 1 Piping/Components System interfaces with a number of other systems that are connected to the Class 1 pressure boundary and, therefore, has many associated functions that support system functions for these other systems. These systems include the Safety Injection System (SI), Residual Heat Removal System (RH), Chemical and Volume Control System (CVCS), and Plant Sampling System. The Class 1 Piping/Components System boundary contains Environmentally Qualified (EQ) components, is credited for use in safe shutdown following Station Blackout (SBO) events and some plant fires (Fire Protection).

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Class 1 Piping/Components System containing components subject to an AMR include the RCS Class 1 piping, valves, and associated fittings; Reactor Coolant Pump (RCP) casings; and Class 1 piping and valves of interfacing support systems that comprise the ASME Class 1 boundary.

The following fluid systems interface with the Class 1 Piping/Components System:

Plant Sampling	Non-Class 1 RCS Components
Residual Heat Removal	Safety Injection
Chemical and Volume Control	Component Cooling Water

System Function Listing

A comprehensive listing of functions associated with the Class 1 portions of the RCS (including Class 1 piping, Reactor Vessel, Reactor Vessel Internals, Steam Generators, and Pressurizer) is provided in the summary below.

Code A	Cri 1	Cri 2	Cri 3				
MAINTAIN REACTOR CORE ASSEMBLY GEOMETRY			FP	EQ	PTS	AT	SB
	X						

Comment: Reactor vessel internals within the Class 1 Piping/Components System perform this primary design system function by supporting the fuel and fuel assemblies.

Code B INTRODUCE EMERGENCY NEGATIVE REACTIVITY TO MAKE THE REACTOR SUBCRITICAL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Boron injection paths within the Class 1 Piping/Components System perform this primary design system function that supplements the control rods.

Code E PROVIDE REACTOR COOLANT PRESSURE BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Components within the Class 1 Piping/Components System perform this primary design system function by containing the coolant for heat transfer and serving as a closed pressure boundary that limits leakage to the Containment Unit 1/2 Building Structure and interconnecting systems.

Code H PROVIDE EMERGENCY HEAT REMOVAL FROM THE REACTOR COOLANT SYSTEM USING SECONDARY HEAT REMOVAL CAPABILITY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Steam Generators within the Class 1 Piping/Components System perform this primary design system function during normal or abnormal operations.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: RCP thermal barriers within the Class 1 Piping/Components System perform this associated design system function by removing heat from the RCPs.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Containment isolation and integrity within the Class 1 Piping/Components System perform this associated design system function to limit the release to the environment through piping that penetrates the Containment.

Code R STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Components such as the reactor vessel and internals within the Class 1 Piping/Components System perform this primary design system function.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Transfer the thermal energy generated in the reactor core to the Feedwater and Condensate System water in the steam generators.

Reflect neutrons back into the reactor core, thus, reducing the amount of thermal neutron leakage.

Moderate or slow down fast neutrons to thermal energies, thus, promoting thermal fission.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Class 1 Piping/Components System shall be capable of the following during a fire:

1. Removing heat from the reactor core and reactor vessel internals and transfer it to the Main and Auxiliary Steam System.
2. Provide pressure control to prevent exceeding RCS design pressure-temperature limits and minimize void formation in the reactor.
3. Monitoring process parameters for wide range pressure and hot and cold leg temperature.
4. Maintaining sufficient inventory control to maintain natural circulation between the reactor core and steam generators.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Class 1 Piping/Components System contains electrical equipment that is environmentally qualified.

Code Z3 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR PRESSURIZED THERMAL SHOCK (10 CFR 50.61)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
					X		

Comment: The Reactor Vessel is maintained within the PTS screening criteria to perform this function.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS STATION BLACKOUT (10 CFR 50.63)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The Class 1 Piping/Components System shall be capable of the following during a SBO:

1. Removing heat from the reactor core and reactor vessel internals and transfer it to the Main and Auxiliary Steam System.
2. Provide pressure control to prevent exceeding RCS design pressure-temperature limits and minimize void formation in the reactor.
3. Monitoring process parameters for wide range pressure and hot and cold leg temperature.
4. Maintaining sufficient inventory control to maintain natural circulation between the reactor core and steam generators.

FSAR Reference

Additional Class 1 Piping/Components System details are provided in Section 3.1, Section 3.2, Section 4.1, Section 4.2, Section 5.2, Section 6.1, and Section 9.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Class 1 Piping/Components System are listed below:

Unit 1	System	Unit 2
LR-541F091 Sh. 1	Reactor Coolant	LR-541F445 Sh. 1
LR-541F091 Sh. 2	Reactor Coolant	LR-541F445 Sh. 2
LR-541F091 Sh. 3	Reactor Coolant	LR-541F445 Sh. 3
LR-541F092	Plant Sampling	LR-541F448
LR-110E017 SH. 1	Safety Injection	LR-110E035 SH. 1
LR-110E018 SH. 1	Residual Heat Removal	LR-110E029 SH. 1
LR-684J741 SH. 3	Chemical and Volume Control	LR-685J175 SH. 3

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.1-1 along with each Component Group’s intended function(s). Major components are addressed separately and therefore are not identified in Table 2.3.1-1. Only the main loop piping, RCPs, and interfacing systems piping are addressed in this table.

Table 2.3.1-1 Class 1 Piping/Components System

Component Group	Intended Function
BOLTING FOR FLANGED PIPING JOINTS, RCP AND VALVE CLOSURE	MECHANICAL CLOSURE INTEGRITY
ORIFICES AND REDUCERS	PRESSURE BOUNDARY RESTRICT FLOW (THROTTLING)
PIPING AND FITTINGS < 4 IN. NPS	PRESSURE BOUNDARY
PIPING AND FITTINGS ≥ 4 IN. NPS	PRESSURE BOUNDARY
PIPING WELDS AND VENT CONNECTIONS (NICKEL ALLOYS)	PRESSURE BOUNDARY
PRIMARY LOOP ELBOWS	PRESSURE BOUNDARY
REACTOR COOLANT PUMP LUGS	STRUCTURAL SUPPORT
REACTOR COOLANT PUMPS (CASING AND MAIN FLANGE)	PRESSURE BOUNDARY
REACTOR COOLANT PUMPS (THERMAL BARRIER FLANGE)	PRESSURE BOUNDARY
THERMAL BARRIER HEAT EXCHANGER TUBING	PRESSURE BOUNDARY
THERMOWELLS	PRESSURE BOUNDARY
VALVES < 4 IN. NPS	PRESSURE BOUNDARY
VALVES ≥ 4 IN. NPS	PRESSURE BOUNDARY

2.3.1.2 **Reactor Vessel**

Component Description

The PBNP RPVs, as the principal component of the RCS, contain the heat-generating core and associated supports, controls and instrumentation, and coolant circulating channels. Primary outlet and inlet nozzles provide for the exit of heated coolant and its return to the RPV for recirculation through the core.

The PBNP Unit 1 RPV consists of a cylindrical shell with a hemispherical bottom head and a flanged and gasketed removable upper head. The Unit 1 RPV shell is fabricated from longitudinally welded plate rings joined by circumferential welds. The PBNP Unit 2 RPV consists of a cylindrical shell with a hemispherical bottom head and a flanged and gasketed removable upper head. The Unit 2 RPV shell is fabricated from integral ring forgings joined by circumferential welds.The RPVs contain the core, core support structures, rod control clusters, thermal shield or neutron shield panels, and other parts directly associated with the core. Inlet and outlet nozzles are located at an elevation between the head flange and the core. The body of the RPVs is low-alloy carbon steel, and the inside surfaces in contact with coolant are clad with austenitic stainless steel to minimize corrosion. The RPVs are supported by steel pads integral with the coolant nozzles.

Subcomponents included for evaluation with the RPV include the CRDM penetrations and housings, Bottom Mounted Instrument (BMI) penetrations and external guide tubing, head vent penetration, seal table pressure boundary fittings, and the head closure bolting.

The primary functions of the reactor vessels are to provide Reactor Coolant pressure boundary and to support vessel internals and instrumentation. The vessels are also in license renewal scope due to 10 CFR 50.61.

FSAR Reference

Additional Reactor Vessel details are provided in Section 3.0 and Section 4.0 of the FSAR.

Subcomponents Subject to an Aging Management Review

The subcomponents of the Reactor Vessel that require aging management review are addressed in Table 2.3.1-2 along with each subcomponent’s intended function(s).

Table 2.3.1-2 Reactor Vessel

Subcomponent	Intended Function
BMI GUIDE TUBES	PRESSURE BOUNDARY SUPPORT THIMBLE TUBES
BOTTOM HEAD DOME	PRESSURE BOUNDARY SUPPORT RV INTERNALS
BOTTOM HEAD TORUS	PRESSURE BOUNDARY SUPPORT RV INTERNALS
CLOSURE HEAD DOME	PRESSURE BOUNDARY
CLOSURE HEAD DOME (INCLUDING LIFTING LUGS)	PRESSURE BOUNDARY
CLOSURE HEAD FLANGE	PRESSURE BOUNDARY
CLOSURE STUDS, NUTS, AND WASHERS	MECHANICAL CLOSURE INTEGRITY
CORE SUPPORT PADS	SUPPORT RV INTERNALS
CRDM HOUSINGS AND FLANGES (ROD TRAVEL AND LATCH)	PRESSURE BOUNDARY
CRDM HOUSING TUBES (HEAD ADAPTERS)	PRESSURE BOUNDARY
INSTRUMENTATION TUBES AND SAFE ENDS	PRESSURE BOUNDARY SUPPORT THIMBLE TUBES
INTERMEDIATE SHELL (INCLUDING CIRCUMFERENTIAL BELTLINE WELD)	PRESSURE BOUNDARY
LOWER SHELL	PRESSURE BOUNDARY

Table 2.3.1-2 Reactor Vessel

Subcomponent	Intended Function
NOZZLE SUPPORT PADS AND EXTERNAL SUPPORT BRACKETS	STRUCTURAL SUPPORT
PRIMARY INLET NOZZLES	PRESSURE BOUNDARY
PRIMARY NOZZLE SAFE ENDS	PRESSURE BOUNDARY
PRIMARY OUTLET NOZZLES	PRESSURE BOUNDARY
REFUELING SEAL LEDGE	STRUCTURAL SUPPORT
RV COMPONENTS (IN CONTACT WITH PRIMARY WATER)	PRESSURE BOUNDARY
SEAL TABLE FITTINGS	PRESSURE BOUNDARY SUPPORT THIMBLE TUBES
UPPER SHELL	PRESSURE BOUNDARY
VENT PIPE	PRESSURE BOUNDARY
VENTILATION SHROUD SUPPORT RING	STRUCTURAL SUPPORT
VESSEL FLANGE	PRESSURE BOUNDARY SUPPORT RV INTERNALS

2.3.1.3 Reactor Vessel Internals

Component Description

The PBNP RVIs consist of two basic assemblies:

- Upper internals assembly that is removed during each refueling operation to obtain access to the reactor core. The top of this assembly is clamped to a ledge below the vessel-head mating surface by the reactor vessel head. The core barrel fuel alignment pins of the lower internals assembly guides the bottom of the upper internals assembly.

- Lower internals assembly that can be removed, if desired, following a complete core unload. This assembly is clamped at the same ledge below the vessel-head mating surface and closely guided at the bottom by radial/clevis assemblies.

Subcomponents included for evaluation with the RVI include support columns and plates, core barrel, baffle former assembly and bolting, instrument and control guides and supports.

The primary function of the RVIs is to support the core, provide flow distribution thru the core, shield the vessel, and guide and support instrumentation and controls.

FSAR Reference

Additional Reactor Vessel Internals details are provided in Section 3.0 and Section 4.0 of the FSAR.

Subcomponents Subject to an Aging Management Review

The subcomponents of the Reactor Vessel Internals that require aging management review are addressed in Table 2.3.1-3 along with each subcomponent's intended function(s).

Table 2.3.1-3 Reactor Vessel Internals

Subcomponent	Intended Function[1]
RVI BAFFLE AND FORMER PLATES	FLOW DISTRIBUTION GAMMA/NEUTRON SHIELDING SUPPORT CORE
RVI BAFFLE/BARREL - FORMER BOLTS	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs

Table 2.3.1-3 Reactor Vessel Internals

Subcomponent	Intended Function[1]
RVI BOTTOM MOUNTED INSTRUMENTATION COLUMN CRUCIFORMS	SUPPORT IN-CORE INSTRUMENTATION
RVI BOTTOM MOUNTED INSTRUMENTATION COLUMNS	SUPPORT IN-CORE INSTRUMENTATION
RVI CLEVIS INSERT BOLT LOCKING MECHANISMS	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI CLEVIS INSERT BOLTS	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI CLEVIS INSERTS	SUPPORT CORE
RVI CORE BARREL - PLATES	FLOW DISTRIBUTION GAMMA/NEUTRON SHIELDING SUPPORT CORE
RVI CORE BARREL FLANGE – RING FORGING, CORE BARREL (GUIDE KEY)	FLOW DISTRIBUTION GAMMA/NEUTRON SHIELDING SUPPORT CORE

Table 2.3.1-3 Reactor Vessel Internals

Subcomponent	Intended Function[1]
RVI CORE BARREL OUTLET NOZZLE - NOZZLE FORGINGS	FLOW DISTRIBUTION
RVI EXPOSED SURFACES AND CREVICE LOCATIONS	NOTE[2]
RVI RCCA FLEXURES, GT SUPPORT PIN (SPLIT PIN)	SUPPORT RCCAs
RVI FLUX THIMBLES	PRESSURE BOUNDARY SUPPORT IN-CORE INSTRUMENTATION
RVI HEAD AND VESSEL ALIGNMENT PINS	SUPPORT RCCAs
RVI HIGH TEMPERATURE AND NEUTRON FLUENCE LOCATIONS	NOTE[2]
RVI HOLDDOWN SPRING	SUPPORT CORE
RVI LOWER CORE PLATE	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION
RVI LOWER CORE PLATE FUEL ALIGNMENT PINS	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION

Table 2.3.1-3 Reactor Vessel Internals

Subcomponent	Intended Function[1]
RVI LOWER SUPPORT COLUMNS, SLEEVES	SUPPORT IN-CORE INSTRUMENTATION SECONDARY CORE SUPPORT SUPPORT CORE
RVI LOWER SUPPORT FORGING	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION
RVI LOWER SUPPORT PLATE COLUMN BOLTS/NUTS	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI RADIAL SUPPORT KEYS	SUPPORT CORE
RVI RCCA GUIDE TUBE BOLTS	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI RCCA GUIDE TUBES, INSERTS, AND FLOW DOWNCOMERS	SUPPORT RCCAs

Table 2.3.1-3 Reactor Vessel Internals

Subcomponent	Intended Function[1]
RVI SECONDARY CORE SUPPORT - BASE PLATE, ENERGY ABSORBER, DIFFUSER PLATE (FLOW MIXER PLATE)	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION
RVI SECONDARY CORE SUPPORT ASSY - GUIDE POST, HOUSING	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION
RVI (HEAD COOLING) SPRAY NOZZLE BODIES AND NOZZLE TIPS	FLOW DISTRIBUTION
RVI THERMAL SHIELD - PLATE MATERIAL, FLEXURES, DOWEL PIN	GAMMA/NEUTRON SHIELDING
RVI UPPER CORE PLATE	FLOW DISTRIBUTION SUPPORT CORE
RVI UPPER CORE PLATE ALIGNMENT PIN	SUPPORT RCCAs
RVI UPPER CORE PLATE FUEL ALIGNMENT PIN	FLOW DISTRIBUTION SUPPORT CORE
RVI UPPER INSTRUMENTATION COLUMN, CONDUIT (TUBING AND SUPPORTS), SPACERS/ CLAMPS	SUPPORT IN-CORE INSTRUMENTATION

Table 2.3.1-3 Reactor Vessel Internals

Subcomponent	Intended Function[1]
RVI UPPER SUPPORT COLUMN AND BOTTOM NOZZLES	SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI UPPER SUPPORT COLUMN - INSTR. FITTINGS - FOR INST. OF INSTRUMENTATION	SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI UPPER SUPPORT COLUMN - USC BASE CASTINGS	SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI UPPER SUPPORT COLUMN BOLTS	FLOW DISTRIBUTION SECONDARY CORE SUPPORT SUPPORT CORE SUPPORT IN-CORE INSTRUMENTATION SUPPORT RCCAs
RVI UPPER SUPPORT PLATE, DEEP BEAM WELDMENT, TOP PLATE, RIBS, HOLLOW ROUNDS	SUPPORT RCCAs

1. See Section 2.2.1 for expanded Intended Function definitions.
2. This generic subcomponent was created in order to address generic aging effects that could apply to any component regardless of intended function.

2.3.1.4 Pressurizer

Component Description

The pressurizer is part of the Reactor Coolant System (RCS) and is located inside containment. The pressurizer is used for RCS pressure control, and consists of the pressurizer vessel equipped with electric heaters, safety valves, relief valves, spray nozzle, interconnecting piping and instrumentation. During operation, the pressurizer contains saturated water and steam maintained at the desired saturation temperature and pressure by the use of electric heaters and the spray nozzle.

The pressurizer pressure control equipment is designed to absorb the reactor coolant volume surges and limit pressure variations during an initial transient period prior to an effective response by the Control Rod Drive and Indication and Nuclear Process Instrumentation System. The pressurizer performs the following functions:

- Maintains the required reactor coolant pressure (pressure boundary function) during steady-state operation and normal heatup and cooldown.
- Limits pressure changes, to an allowable range, that are caused by reactor coolant thermal expansion and contraction during normal plant load changes and transients.

The pressurizer scope is limited to the pressurizer pressure boundary up to and including the nozzles, nozzle safe ends, nozzle-to-safe end welds, and the support skirt and flange. Boundaries between the pressurizer and associated systems and components are typically drawn at the pressurizer interface. As such, the following systems/components are not considered as part of the pressurizer:

- Class 1 piping and the attachment welds to the pressurizer nozzles/safe ends. Refer to Section 2.3.1.1 for the review of these components.
- Instrument piping/tubing, valves, manifolds and instrumentation beyond the class 1 boundary. Refer to Section 2.3.1.6 for the review of these components.
- The pressurizer support skirt and support flange, which are welded to the lower pressurizer head, are part of the pressurizer. However, the support attachment bolting is not part of the pressurizer. Refer to Section 2.4.10 for the review of these components.

FSAR Reference

Additional pressurizer details are provided in Section 4.0 of the FSAR.

Subcomponents Subject to an Aging Management Review

The subcomponents of the pressurizer that require aging management review are addressed in Table 2.3.1-4 along with each subcomponent's intended function(s).

Table 2.3.1-4 Pressurizer

Subcomponent	Intended Function
PZR HEATER WELL AND HEATER SHEATH	PRESSURE BOUNDARY
PZR INSTRUMENT NOZZLES	PRESSURE BOUNDARY
PZR LOWER HEAD	PRESSURE BOUNDARY
PZR MANWAY COVER	PRESSURE BOUNDARY
PZR MANWAY COVER BOLTS	PRESSURE BOUNDARY MECHANICAL CLOSURE INTEGRITY
PZR RELIEF NOZZLE	PRESSURE BOUNDARY
PZR RELIEF NOZZLE SAFE END	PRESSURE BOUNDARY
PZR SAFETY NOZZLE	PRESSURE BOUNDARY
PZR SAFETY NOZZLE SAFE END	PRESSURE BOUNDARY
PZR SHELL	PRESSURE BOUNDARY
PZR SPRAY NOZZLE	PRESSURE BOUNDARY
PZR SPRAY NOZZLE SAFE END	PRESSURE BOUNDARY
PZR SPRAY NOZZLE THERMAL SLEEVE	PRESSURE BOUNDARY[1]
PZR SUPPORT SKIRT AND FLANGE	STRUCTURAL SUPPORT
PZR SURGE NOZZLE	PRESSURE BOUNDARY

Table 2.3.1-4 Pressurizer

Subcomponent	Intended Function
PZR SURGE NOZZLE SAFE END	PRESSURE BOUNDARY
PZR SURGE NOZZLE THERMAL SLEEVE	PRESSURE BOUNDARY[1]
PZR UPPER HEAD	PRESSURE BOUNDARY

1. The thermal sleeves are not part of the pressure boundary, but do provide thermal shielding to minimize nozzle low cycle thermal fatigue of the pressure boundary.

2.3.1.5 Steam Generators

Component Description

The Steam Generators (SG) form the boundary between the radioactive Reactor Coolant System (RCS) and the non-radioactive secondary systems. There are two essentially identical steam generators installed in each containment, one in each Reactor Coolant System loop. The SG is a vertical shell and tube heat exchanger, where heat transferred from a single-phase fluid at high temperature and pressure (reactor coolant) on the tube side is used to generate a two-phase (steam-water) mixture at a lower temperature and pressure on the shell side. The reactor coolant flows through the primary side, or inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator.

The steam-water mixture is generated on the secondary, or shell side of the steam generator. Feedwater from the Feedwater and Condensate System enters the steam generator through the feed ring, mixes with recirculated fluid, flows downward around the tube bundle inner shroud, then enters the tube bundle area where heat is transferred from the RCS. The mixture is heated and flows upward through the tube bundle by natural circulation, changing into a steam-water mixture. As the steam-water mixture leaves the tube bundle, it enters the moisture separator section where water is extracted from the steam in two stages. Essentially dry steam exits the moisture separation section and exits the steam generator through the steam nozzle to the Main and Auxiliary Steam System.

The steam nozzle contains a flow limiting device which operates on the venturi principle. The flow limiting device is intended to limit steam flow in the event of a postulated steam line break accident.

Boundaries between the steam generators and associated systems and components are drawn at the steam generator interface. The Steam Generators interface with the following systems:

- Class 1 Piping. Refer to Section 2.3.1.1 for the review of these components.
- Feedwater and Condensate. Refer to Section 2.3.4.2 for the review of these components.
- Main and Auxiliary Steam. Refer to Section 2.3.4.1 for the review of these components.
- The support attachment bolting, support columns and support assemblies are not part of the Steam Generators. Refer to Section 2.4.10 for the review of these components.

The primary functions of the Steam Generators are pressure boundary, both primary and secondary side; heat removal from the Reactor Coolant System; and structural support. The Steam Generators are also required for response to certain fire and Station Blackout scenarios.

FSAR Reference

Additional Steam Generators details are provided in Section 4.0 of the FSAR.

Subcomponents Subject to an Aging Management Review

The subcomponents of the Steam Generators that require aging management review are addressed in Table 2.3.1-5 along with each subcomponent's intended function(s).

Table 2.3.1-5 Steam Generators

Subcomponent	Intended Function
SG ANTI-VIBRATION BARS	PROVIDE SUPPORT
SG BLOWDOWN PIPING NOZZLES AND SECONDARY SIDE SHELL PENETRATIONS	PRESSURE BOUNDARY (SECONDARY)
SG COMPONENTS (IN CONTACT WITH PRIMARY WATER)	PRESSURE BOUNDARY (PRIMARY)

Table 2.3.1-5 Steam Generators

Subcomponent	Intended Function
SG DIVIDER PLATE	FLOW DISTRIBUTION
SG FEEDWATER NOZZLE	PRESSURE BOUNDARY (SECONDARY)
SG PRIMARY CHANNEL HEAD	PRESSURE BOUNDARY (SECONDARY)
SG PRIMARY INLET AND OUTLET NOZZLE SAFE ENDS	PRESSURE BOUNDARY (PRIMARY)
SG PRIMARY INLET AND OUTLET NOZZLES	PRESSURE BOUNDARY (PRIMARY)
SG PRIMARY MANWAY BOLTING	PRESSURE BOUNDARY (PRIMARY)
SG PRIMARY MANWAYS	PRESSURE BOUNDARY (PRIMARY)
SG SECONDARY CLOSURES	PRESSURE BOUNDARY (SECONDARY)
SG SECONDARY SIDE CLOSURE BOLTING	PRESSURE BOUNDARY (SECONDARY)
SG SEISMIC LUGS	PROVIDE SUPPORT
SG STEAM FLOW LIMITER	RESTRICT FLOW (THROTTLING)
SG TUBE PLUGS (MECHANICAL)	PRESSURE BOUNDARY (PRIMARY)
SG STEAM OUTLET NOZZLE	PRESSURE BOUNDARY (SECONDARY)
SG SUPPORT PADS	PROVIDE SUPPORT
SG TRANSITION CONE GIRTH WELD	PRESSURE BOUNDARY (SECONDARY)

Table 2.3.1-5 Steam Generators

Subcomponent	Intended Function
SG TUBE BUNDLE WRAPPER AND WRAPPER SUPPORT SYSTEM	PROVIDE SUPPORT
SG TUBE SUPPORT PLATES	PROVIDE SUPPORT
SG TUBESHEET	PRESSURE BOUNDARY (PRIMARY & SECONDARY)
SG UPPER AND LOWER SHELL, ELLIPTICAL HEAD AND TRANSITION CONE	PRESSURE BOUNDARY (SECONDARY)
SG U-TUBES	PRESSURE BOUNDARY

2.3.1.6 Non-Class 1 RCS Components System

System Description

The Non-Class 1 RCS Components System includes all safety Class 2, 3 and non-nuclear safety grade equipment used to functionally support the Reactor Coolant System (RCS) intended functions. Non-Class 1 RCS Components are used to sense and provide signals for reactor trip and the Engineered Safety Features Actuation System. The Non-Class 1 RCS Components System contains Environmentally Qualified (EQ) components and is also credited for use in safe shutdown following Station Blackout (SBO) events and some plant fires (Fire Protection).

The RCS Class 1 Piping, Steam Generators, Pressurizer, and Reactor Vessel are each evaluated separately.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Non-Class 1 RCS Components System containing components subject to an AMR include all RCS interconnected non-Class 1 piping, RCP motor oil coolers, RCP flywheel, and pressurizer power operated relief valve (PORV) operators, solenoids, discharge piping, pressurizer relief tank (PRT), and associated piping and valves to support the system intended functions.

The following fluid systems interface with the Non-Class 1 RCS Components System:

Class 1 Piping/Components	Plant Air
Component Cooling Water	

System Function Listing

A comprehensive listing of functions associated with the Non-Class 1 RCS Components System, or specific components contained in the system, is provided in the summary below.

Code D SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Instrumentation within the Non-Class 1 RCS Components System perform this primary design system function by detecting, initiating, and actuating automatic safety functions.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: RCP oil coolers within the Non-Class 1 RCS Components System perform this associated design system function by removing heat from the RCPs.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Containment isolation and integrity within the Non-Class 1 RCS Components System perform this associated design system function to limit the release to the environment through piping that penetrates the Containment.

Code S	Cri 1	Cri 2	Cri 3				
SPECIAL CAPABILITY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: During accidents, the Non-Class 1 RCS Components System provides signals for Reg. Guide 1.97 Type B, C, D post-accident monitoring variables.

Code X	Cri 1	Cri 2	Cri 3				
FUNCTION APPLICABLE AT COMPONENT LEVEL			FP	EQ	PTS	AT	SB
	X						

Comment: Reg. Guide 1.97, Type A post-accident monitoring variables for instruments in this system.

Code Z1	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)			FP	EQ	PTS	AT	SB
			X				

Comment: Components within the Non-Class 1 RCS Components System shall be capable of providing the following functions during some fire scenarios:

Removing heat from the reactor core and reactor vessel internals and transfer it to the Main and Auxiliary Steam System.

Provide pressure control to prevent exceeding RCS design pressure-temperature limits and minimize void formation in the reactor.

Monitoring process parameters for wide range pressure and hot and cold leg temperature.

Maintaining sufficient inventory control to maintain natural circulation between the reactor core and steam generators.

Code Z2	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)			FP	EQ	PTS	AT	SB
				X			

Comment: The Non-Class 1 RCS Components System contains electrical equipment that is environmentally qualified.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS STATION BLACKOUT (10 CFR 50.63)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The Non-Class 1 RCS Components System shall be capable of providing the following functions during some SBO scenarios:

Removing heat from the reactor core and reactor vessel internals and transfer it to the Main and Auxiliary Steam System.

Provide pressure control to prevent exceeding RCS design pressure-temperature limits and minimize void formation in the reactor.

Maintaining sufficient inventory control to maintain natural circulation between the reactor core and steam generators.

Monitoring process parameters for RCS pressure and temperature.

FSAR Reference

Additional Non-Class 1 RCS Components System details are provided in Section 4.2, Section 5.1, Section 5.2, Section 7.0, and Section 9.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Non-Class 1 RCS Components System are listed below:

Unit 1	Unit 2
LR-541F091 Sh. 1	LR-541F445 Sh. 1
LR-541F091 Sh. 2	LR-541F445 Sh. 2
LR-541F091 Sh. 3	LR-541F445 Sh. 3

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.1-6 along with each Component Group’s intended function(s).

Table 2.3.1-6 Non-Class 1 RCS Components System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY

Table 2.3.1-6 Non-Class 1 RCS Components System

Component Group	Intended Function
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW INDICATORS	PRESSURE BOUNDARY
FLYWHEEL	FLOW CONTROL
HEAT EXCHANGER	PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
SEAL TABLE	SUPPORT IN-CORE INSTRUMENTATION
TANKS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY
VALVE OPERATOR	PRESSURE BOUNDARY

2.3.2 Engineered Safety Features

The following systems are addressed in this section:

- Safety Injection System (Section 2.3.2.1)
- Containment Spray System (Section 2.3.2.2)
- Residual Heat Removal System (Section 2.3.2.3)
- Containment Isolation Components System (Section 2.3.2.4)

2.3.2.1 Safety Injection System

System Description

The Safety Injection (SI) System supports the Reactor Coolant System (RCS) inventory and reactivity control during accident and post-accident conditions by automatically delivering borated water to the reactor vessel for cooling under high and low reactor coolant pressure conditions. Additionally, the Safety Injection System serves to insert negative reactivity into the reactor core in the form of borated water during an uncontrolled plant cooldown following a steam line break or an accidental steam release. The SI System contains Environmentally Qualified (EQ) components and is also credited for use in safe shutdown following some plant fires (Fire Protection).

The SI System for each PBNP unit consists of the following principal components: two passive accumulators (including the nitrogen supply boundary to these tanks), Refueling Water Storage Tank (RWST), two safety injection pumps (high pressure injection), and the associated piping and valves to support the system intended functions. The residual heat removal pumps perform the low pressure safety injection function to support the SI System. (The residual heat removal components are addressed in the Residual Heat Removal System.) The accumulators are passive devices that discharge into the cold leg of each loop. During MODES 1 and 2, the RWST is aligned to the suction of the SI pumps, containment spray pumps, and residual heat removal pumps. After the injection phase, spilled and sprayed water collects in the Containment sump. The RH/SI Systems can then be aligned to take suction from the Containment sump, cool the fluid, and supply cooled water to the SI System and the Containment Spray System for re-injection or spray.

Class 1 boundary components that carry a SI equipment designation are addressed in the Class 1 Piping/Components System. The Safety Injection System is a standby system during normal plant operation.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Safety Injection System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection and Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Safety Injection System containing components subject to an AMR extend from the accumulators and RWST to the RCS and include the high-head safety injection pumps.

The following fluid systems interface with the Safety Injection System:

Class 1 Piping/Components	Spent Fuel Cooling
Residual Heat Removal	Chemical and Volume Control
Containment Spray	Component Cooling Water
Plant Air	

System Function Listing

A comprehensive listing of functions associated with the Safety Injection System, or specific components contained in the system, is provided in the summary below.

Code B	Cri 1	Cri 2	Cri 3				
INTRODUCE EMERGENCY NEGATIVE REACTIVITY TO MAKE THE REACTOR SUBCRITICAL			FP	EQ	PTS	AT	SB
	X						

Comment: The Safety Injection System increases the boron concentration in the Reactor Coolant System during the injection phase of Safety Injection to ensure adequate reactor shutdown margin in the event of a secondary pipe break.

The Safety Injection System provides sufficient boron to maintain an adequate post-LOCA sump mean boron concentration to ensure shutdown of the core with all control rods out.

The Safety Injection System delivers borated water to the Reactor Coolant System, as necessary, to compensate for Xenon decay to maintain hot shutdown margin.

Code E	Cri 1	Cri 2	Cri 3				
PROVIDE REACTOR COOLANT PRESSURE BOUNDARY			FP	EQ	PTS	AT	SB
	X						

Comment: The Safety Injection System piping and components that are part of the reactor coolant pressure boundary are designed to maintain pressure boundary integrity during all modes of plant operation.

Code G PROVIDE EMERGENCY CORE COOLANT WHERE THE ECCS PROVIDES COOLANT DIRECTLY TO THE CORE	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Safety Injection System delivers borated cooling water to the Reactor Coolant System during the injection phase of Safety Injection to support core cooling.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The seal water heat exchangers on the SI pumps perform this associated system function.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Safety Injection System has containment Isolation valves that shut on a Containment Isolation Signal to assure that no unrestricted release of radioactivity can occur. Also, a combination of normally shut valves and a portion of the Safety Injection System piping outside containment passively serve as a containment boundary (a closed loop outside of containment.)

Code L PROVIDE EMERGENCY HEAT REMOVAL FROM PRIMARY CONTAINMENT AND PROVIDE CONTAINMENT PRESSURE CONTROL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Safety Injection System provides the liquid capacity in the form of the Refueling Water Storage Tank for the Containment Spray System to provide emergency heat removal from primary containment and provide containment pressure control.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Safety Injection System provides the following functions which do not meet the criteria listed in 10 CFR 54.4(a)(1), (2) or (3):

The Safety Injection System provides a source of borated water during refueling shutdown to flood the refueling cavity.

The Safety Injection System provides a backup source of water during normal plant operations for the Chemical and Volume Control System charging pumps in the event the normal source is lost. The Refueling Water Storage Tank provides one of two required boric acid sources sufficient to provide the required shutdown margin at cold shutdown, xenon-free conditions from any expected operating condition.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety components in the SI System, whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Safety Injection System shall be capable of isolating RCS boundaries, preventing loss of inventory of the RWST and supplying RWST inventory to the Chemical and Volume Control System to support reactor coolant make-up capability.

The Safety Injection System shall be capable of providing RHR recirculation flowpaths for maintaining decay heat removal.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Safety Injection System contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Safety Injection System details are provided in Section 4.1, Section 5.2, Section 6.2, and Section 9.1.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Safety Injection System are listed below:

Unit 1	Unit 2
LR - 110E017 Sh 1	LR - 110E035 Sh 1
LR - 110E017 Sh 2	LR - 110E035 Sh 2

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.2-1 along with each Component Group's intended function(s).

Table 2.3.2-1 Safety Injection System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW ELEMENTS	PRESSURE BOUNDARY
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
LEVEL ELEMENTS	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RESTRICTING ORIFICES	PRESSURE BOUNDARY RESTRICTS FLOW
TANKS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.2.2 Containment Spray System

System Description

The Containment Spray System is designed to remove sufficient heat from the Containment atmosphere following an accident condition to maintain the Containment pressure below design limits. The Containment Spray System, in conjunction with the sodium hydroxide (NaOH) tank, is also capable of reducing the iodine in the Containment atmosphere such that the offsite radiation exposure resulting from a LOCA is within the guidelines established by 10 CFR 100. The addition of NaOH is also credited to reduce the pH levels within the Containment sump in order to prevent chloride stress corrosion cracking (SCC). The Containment Spray System contains Environmentally Qualified (EQ) components and some components are credited for use in safe shutdown following some plant fires (Fire Protection).

The Containment Spray System for each PBNP unit consists of the following principal components: two spray pumps, one NaOH tank, two spray headers, two eductors, spray nozzles, and the associated piping and valves to support the system intended functions. The system initially takes suction from the Refueling Water Storage Tank (RWST). When a low level is reached in the RWST, the spray pump suction is fed from the discharge of the residual heat removal pumps (using sump recirculation) if continued spray is required.

During the period of time that the spray pumps draw from the RWST, spray additive will be added to the refueling water in each train by using a liquid eductor enabled by the spray pump discharge. The result will be a solution suitable for the removal of iodine. The Containment Spray System is a standby system during normal plant operation.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection and Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Containment Spray System containing components subject to an AMR extend from the pump suction supplies from the RWST or the RHR pump discharge, to the spray headers and include the NaOH tank, eductors and spray pumps.

The following fluid systems interface with the Containment Spray System:

Residual Heat Removal	Component Cooling Water
Safety Injection	Plant Air

System Function Listing

A comprehensive listing of functions associated with the Containment Spray System, or specific components contained in the system, is provided in the summary below.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The seal water heat exchangers for the Containment Spray pumps perform the associated system function.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Containment Spray System has containment isolation valves in lines penetrating the Containment to prevent the release of radioactivity to the environment.

Code L PROVIDE EMERGENCY HEAT REMOVAL FROM PRIMARY CONTAINMENT AND PROVIDE CONTAINMENT PRESSURE CONTROL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Containment Spray System delivers buffered cooling water to the containment spray headers during the injection phase of safety injection to support containment cooling and ensure containment pressure does not exceed its design value.

Code M PROVIDE EMERGENCY REMOVAL OF RADIOACTIVE MATERIAL FROM THE PRIMARY CONTAINMENT ATMOSPHERE	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Containment Spray System delivers water to the containment spray headers during the injection phase of safety injection in support of spraying down containment for removal of elemental iodine from the containment atmosphere in the event of a Loss of Coolant Accident.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Components within the Containment Spray System perform non-safety function, such as test connections and misc. instrumentation.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Containment Spray System shall be capable of being isolated to prevent loss of inventory of the RWST to support reactor coolant make-up capability.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Containment Spray System contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Containment Spray System details are provided in Section 5.2, Section 6.4, Section 9.1.1, and Appendix C of the FSAR.

License Renewal Drawings

The license renewal drawings for the Containment Spray System are listed below:

Unit 1	Unit 2
LR - 110E017 Sh 3	LR - 110E035 Sh 3

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.2-2 along with each Component Group’s intended function(s).

Table 2.3.2-2 Containment Spray System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY

Table 2.3.2-2 Containment Spray System

Component Group	Intended Function
EDUCTOR	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW ELEMENTS	PRESSURE BOUNDARY
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RESTRICTING ORIFICES	PRESSURE BOUNDARY RESTRICTS FLOW
SPRAY NOZZLE	FLOW CONTROL
TANKS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.2.3 **Residual Heat Removal System**

System Description

The Residual Heat Removal (RH) System is a dual-purpose system, operating as a portion of the Safety Injection System during normal operations, and removing reactor decay heat during plant cool down and shutdown/refueling operations. The Residual Heat Removal System pumps and valves automatically deliver borated water to the reactor vessel for cooling under low Reactor Coolant System (RCS) pressure conditions. During MODES 1 and 2, the Refueling Water Storage Tank (RWST) is aligned to the suction of the RH pumps. After the injection phase, the RH pumps will take suction from the

Containment sump, circulate the spilled coolant through the RH heat exchangers, and return the coolant to the reactor via the reactor vessel nozzles. If depressurization of the RCS proceeds slowly, the safety injection pumps are aligned to take suction from the RH pump discharge, and inject water into the RCS cold legs. The RH pumps and heat exchangers, in conjunction with the Containment Spray System, may also be used during the recirculation phase to supply water from the Containment sump for use in heat removal and pressure control of the Containment atmosphere. The RH System contains Environmentally Qualified (EQ) components and is also credited for use following some plant fires (Fire Protection).

For normal plant cooldown and shutdown, the RH System is designed to transfer the fission product decay heat and other residual heat from the reactor core to the Component Cooling Water System. Decay heat cooling is initiated by aligning the RH pumps to take suction from RCS loop A hot leg and discharge through the RH heat exchangers to the loop B cold leg.

The RH System for each PBNP unit consists of the following principal components: two RH pumps, two heat exchangers, and the associated piping and valves to support the system intended functions. There are Class 1 boundary components within the high temperature RCS envelope that carry a RH equipment designation. These components are addressed in the Class 1 Piping/Components System. The Residual Heat Removal System is a standby system during normal plant operation.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection and Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Residual Heat Removal System containing components subject to an AMR extend from the RH pump suction supplies from the RWST or the containment sump, system inter-connections to the RCS, and the safety injection and containment spray pump suction supply (for recirculation operation).

The following fluid systems interface with Residual Heat Removal:

Class 1 Piping/Components	Containment Spray
Safety Injection	Chemical and Volume Control
Component Cooling Water	Plant Air
Spent Fuel Cooling	

System Function Listing

A comprehensive listing of functions associated with the Residual Heat Removal System, or specific components contained in the system, is provided in the summary below.

Code E	Cri 1	Cri 2	Cri 3				
PROVIDE REACTOR COOLANT PRESSURE BOUNDARY			FP	EQ	PTS	AT	SB
	X						

Comment: The Residual Heat Removal piping and components that are part of the reactor coolant pressure boundary are designed to maintain pressure boundary integrity during all modes of plant operation.

Code F	Cri 1	Cri 2	Cri 3				
REMOVE RESIDUAL HEAT FROM THE RCS			FP	EQ	PTS	AT	SB
	X						

Comment: The Residual Heat Removal System, in conjunction with the Safety Injection System, recirculates and cools the water that is collected in the containment sump and returns it to the Reactor Coolant System during the ECCS recirculation phase to support long term cooling.

The Residual Heat Removal System removes decay heat from the Reactor Coolant System for mitigating the radiological consequences of the rupture of a control rod mechanism housing (RCCA ejection), locked rotor, main steam line break and steam generator tube rupture accident.

Code G	Cri 1	Cri 2	Cri 3				
PROVIDE EMERGENCY CORE COOLANT WHERE THE ECCS PROVIDES COOLANT DIRECTLY TO THE CORE			FP	EQ	PTS	AT	SB
	X						

Comment: The Residual Heat Removal System, in conjunction with the Safety Injection System, delivers borated cooling water to the Reactor Coolant System during the ECCS injection phase to support core cooling.

Code J	Cri 1	Cri 2	Cri 3				
PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS			FP	EQ	PTS	AT	SB
	X						

Comment: The seal water heat exchangers for the RH pumps perform this associated system function.

Code K	Cri 1	Cri 2	Cri 3				
PROVIDE PRIMARY CONTAINMENT BOUNDARY			FP	EQ	PTS	AT	SB
	X						

Comment: The Residual Heat Removal System has containment isolation valves that shut on a Containment Isolation Signal to assure that no unrestricted release of radioactivity can occur. The portion of the Residual Heat Removal System outside containment is a closed loop system.

Code L PROVIDE EMERGENCY HEAT REMOVAL FROM PRIMARY CONTAINMENT AND PROVIDE CONTAINMENT PRESSURE CONTROL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The RH System provides the capability to supply water to the suction of the Containment Spray pumps when in recirculation mode.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Safety Injection System provides the following functions which do not meet the criteria listed in 10 CFR 54.4(a)(1), (2) or (3):

The Residual Heat Removal (RH) System removes sensible heat and decay heat from the Reactor Coolant System (RCS) during cooldown, cold shutdown and refueling shutdown to establish and maintain cold shutdown or refueling shutdown.

The RH System transfers refueling water between the refueling water storage tank and the refueling canal during refueling shutdown to flood and subsequently drain a portion of the refueling canal.

The RH System provides a flow path from the RCS to the Chemical and Volume Control System (CVCS) letdown line downstream of the letdown orifices during RCS heatup and cooldown to maintain adequate letdown flow at low RCS pressures for reactor coolant purification, RCS inventory control and pressure control.

The RH System circulates refueling water from the spent fuel pool cleanup sub-system during refueling operations to support the process of maintaining refueling canal water clarity and purity.

The RH System transports water from the refueling canal drains to the CVCS purification equipment.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Residual Heat Removal System shall be capable of achieving and maintaining decay heat removal from the RCS.

The Residual Heat Removal System shall be capable of monitoring process parameters for RH pump discharge pressure and RH heat exchanger outlet temperature.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Residual Heat Removal System contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Residual Heat Removal System details are provided in Section 5.2, Section 6.2, Section 6.4.2, Section 9.1.1, and Section 9.2 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Residual Heat Removal System are listed below:

Unit 1	Unit 2
LR-110E017, Sh. 1	LR-110E029, Sh. 1
LR-110E018, Sh. 1	LR-110E035, Sh. 1

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.2-3 along with each Component Group's intended function(s).

Table 2.3.2-3 Residual Heat Removal System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY PROVIDE FILTRATION
FLOW ELEMENTS	PRESSURE BOUNDARY

Table 2.3.2-3 Residual Heat Removal System

Component Group	Intended Function
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RESTRICTING ORIFICES	PRESSURE BOUNDARY RESTRICTS FLOW
SUMP SCREEN	PROVIDE FILTRATION
TANKS	PRESSURE BOUNDARY
THERMOWELLS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY
VALVE OPERATOR	PRESSURE BOUNDARY

2.3.2.4 Containment Isolation Components System

System Description

The Containment Isolation Components System was created as a virtual system for those systems whose only SR function is to provide a Containment isolation function.

Each system whose piping penetrates the Containment leakage-limiting boundary is designed to maintain or establish isolation of the Containment from the outside environment under any accident condition for which isolation is required. Piping penetrating the Containment is designed for pressures at least equal to the Containment design pressure. Containment isolation boundaries are provided as necessary in lines penetrating the Containment to ensure that no unrestricted release of radioactivity can occur.

Valving for penetrations can be either manually or automatically actuated. For manual valves, their normal lineup is in the closed position during periods requiring Containment integrity. For automatic valves, control signals are provided that position the valves to perform their intended function.

Components addressed within the Containment Isolation Components System include Containment penetration isolation valves, test flanges, caps, and the associated piping and valves to support the system intended functions. The system includes demineralized water penetrations, Radiation Monitoring System Containment air sample penetrations, spare Containment penetrations, and tubing and valves that support air-lock testing.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Containment Isolation Components System containing components subject to an AMR extend between the penetration isolation valves and include penetration test valves, flanges, and piping for demineralized water sub-system penetrations, Radiation Monitoring System Containment air sample penetrations, spare Containment penetrations, and associated airlock support equipment.

The following mechanical systems interface with the Containment Isolation Components System:

Radiation Monitoring	Treated Water
Heating Steam	Plant Air

System Function Listing

A comprehensive listing of functions associated with the Containment Isolation Components System, or specific components contained in the system, is provided in the summary below.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Components within the Heating Steam System perform this associated system function. Heating steam to the Containment at penetrations P52 and P53 are terminated, capped, and welded on both ends to prevent the release of radioactivity to the environment.

Containment isolation valves within the Radiation Monitoring System perform this primary design system function to prevent the release of radioactivity to the environment.

The DI water connections to both containments are also addressed here.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Containment Isolation Components System contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Containment Isolation Components System details are provided in Section 5.2 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Containment Isolation Components System are listed below:

Unit 1	Unit 2
LR-PBM-231, Sh. 2	LR-PBM-231, Sh. 2
LR-M-215, Sh. 2	LR-M-2215, Sh. 2
LR-M-224	LR-M-224

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.2-4 along with each Component Group's intended function(s).

Table 2.3.2-4 Containment Isolation Components System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
PIPING AND FITTINGS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3 Auxiliary Systems

The following systems are addressed in this section:

- Chemical Volume and Control System (Section 2.3.3.1)
- Component Cooling Water System (Section 2.3.3.2)
- Spent Fuel Cooling System (Section 2.3.3.3)
- Waste Disposal System (Section 2.3.3.4)
- Service Water System (Section 2.3.3.5)
- Fire Protection System (Section 2.3.3.6)
- Heating Steam System (Section 2.3.3.7)
- Emergency Power System (Section 2.3.3.8)
- Containment Ventilation System (Section 2.3.3.9)
- Essential Ventilation System (Section 2.3.3.10)
- Treated Water System (Section 2.3.3.11)
- Circulating Water System (Section 2.3.3.12)
- Fuel Handling System (Section 2.3.3.13)
- Plant Sampling System (Section 2.3.3.14)
- Plant Air System (Section 2.3.3.15)
- Containment Hydrogen Detectors and Recombiner System (Section 2.3.3.16)

2.3.3.1 Chemical and Volume Control System

System Description

The Chemical and Volume Control System controls and maintains Reactor Coolant System (RCS) inventory and purity through the process of charging and letdown, and provides seal injection flow to the reactor coolant pump (RCP) seals. In addition to the reactivity control achieved by the control rods, the Chemical and Volume Control System (CVCS) also provides reactivity control by regulating the concentration of boric acid solution in the RCS. In order to perform the above functions, a continuous feed-and-bleed process (charging and letdown) is maintained between the RCS and the CVCS. The CVCS System contains Environmentally Qualified (EQ) components and is also credited for use in safe shutdown following Station Blackout (SBO) events and some plant fires (Fire Protection).

The CVCS System for each PBNP unit consists of the following principal components: volume control tank (VCT), three positive displacement charging pumps, regenerative heat exchanger, non-regenerative heat exchanger, excess letdown heat exchanger, seal water heat exchanger, demineralizers, and the associated piping and valves to support the system functions.

The charging portion of the system consists of the three charging pumps taking suction from either the VCT or the RWST, and pumping forward to the RCS via either the RCP Seal injection or through the Regenerative HX into the A loop cold leg. The letdown portion of the system consists of the regenerative HX and the non-regenerative HX which cool the RCS letdown. Letdown flow is controlled via three parallel orifices that also serve to reduce the pressure. Letdown flow is then routed through filters and demineralizers to clean up the water, which is eventually returned to the VCT. An alternate means of letdown is through the Excess Letdown HX. RCP seal return flow passes through a Containment isolation valve and is then cooled by the seal water heat exchanger.

There are Class 1 boundary components that carry a CVCS equipment designation (CV). These components are addressed in the Class 1 Piping/Components System. The Chemical and Volume Control System is in continuous service during normal plant operation.

The in-scope portion of the CVCS System includes the flow path from the RWST, through the charging pumps into the RCS. CVCS lines coming from the RCS are in-scope through the containment isolation valves (CIVs). The main letdown line is in-scope through the non-regenerative HX (which is outside of containment) due to potential non-safety affecting safety issues (Criterion 2).

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Chemical and Volume Control System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Chemical and Volume Control System containing components subject to an AMR extend from the RWST to the RCS, and from the RCS to system CIVs, including pumps, heat exchangers, piping and valves.

The following fluid systems interface with the Chemical and Volume Control System:

Class 1 Piping/Components	Residual Heat Removal
Plant Air	Component Cooling
Safety Injection	Waste Disposal

System Function Listing

A comprehensive listing of functions associated with the Chemical and Volume Control System, or specific components contained in the system, is provided in the summary below.

Code E PROVIDE REACTOR COOLANT PRESSURE BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Piping and components within the Chemical and Volume Control System perform this associated design system function to support the safety function of the RC System.

Code J	Cri 1	Cri 2	Cri 3				
PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS			FP	EQ	PTS	AT	SB
	X						

Comment: The excess letdown, nonregenerative, and RCP seal water heat exchangers within the Chemical and Volume Control System perform this associated design system function for pressure boundary.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Isolation valves within the Chemical and Volume Control System perform this associated design system function to provide Containment isolation.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The CVCS System processes RCS letdown to reuse the boric acid, or reuse the water as reactor makeup water.

Provide normal and transient boration and water inventory of RCS.

Cooldown PZR when RCPs are off and PZR Spray is unavailable (Aux. Spray).

Provide RCS pressure control to support RCP operation during solid operations for heatup and cooldown.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety components in the CVCS System, whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Chemical and Volume Control System shall be capable of providing long term reactivity control by providing borated water from the RWST.

The Chemical and Volume Control System shall be capable of providing make-up water to the RCS from the RWST to support reactor coolant make-up capability.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Chemical Volume and Control System contains electrical equipment that is environmentally qualified.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: Chemical and Volume Control System components (other than CIVs) provide Containment isolation functions during an SBO.

FSAR Reference

Additional Chemical and Volume Control System details are provided in Section 5.2 and Section 9.3 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Chemical and Volume Control System are listed below:

Unit 1
LR-684J741, Sh. 2
LR-684J741, Sh. 3
LR-PBM-231, Sh1
LR-541F092
LR-541F448

Unit 2
LR-685J175, Sh. 2
LR-685J175, Sh. 3
LR-PBM-231, Sh1

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-1 along with each Component Group's intended function(s).

Table 2.3.3-1 Chemical and Volume Control System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY PROVIDE FILTRATION
FLOW ELEMENTS	PRESSURE BOUNDARY
HEAT EXCHANGER	PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
TANKS	PRESSURE BOUNDARY
THERMOWELLS	PRESSURE BOUNDARY

Table 2.3.3-1 Chemical and Volume Control System

Component Group	Intended Function
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.2 Component Cooling Water System

System Description

The Component Cooling Water System provides heat removal capabilities to support the operation of both PBNP units and various equipment. The Component Cooling Water System removes residual and sensible heat from the Reactor Coolant System (RCS) via the residual heat removal (RH) heat exchangers during the recirculation phase of safety injection (SI) to support long-term core cooling; removes heat from the RH, SI, and Containment Spray pump seal coolers to maintain the integrity of the pump seals; precludes Containment leakage through the Component Cooling Water System (CC) piping penetrations following accidents to limit the release of radioactive materials; removes heat from the Reactor Coolant Pump (RCP) thermal barrier cooling coils to ensure RCS integrity; and removes heat from the RH heat exchangers to mitigate the consequences of a postulated main steam line break (MSLB) or steam generator tube rupture (SGTR) accident. The CC System contains Environmentally Qualified (EQ) components and is also credited for use following a Station Blackout event (SBO) and for some plant fires (Fire Protection). A spare CC pump motor with power cables is provided for a repair if a fire causes damage to all four CC pumps. These Appendix R components are addressed in the electrical AMR. The CC System is seismic Class I design with the exception of the CC branch lines to various radwaste components. Recent LBB analyses have allowed the CC System to be classified as a closed-loop inside Containment.

The CC System consists of four pumps, four heat exchangers, two surge tanks and the associated piping and valves to support the system functions. The CC loop in each unit consists of two pumps, two heat exchangers, a surge tank, a supply header, and a return header. The capability to use the pumps assigned to one loop to supply both loops is also provided. Normally the CC loops of each of the two units operate independently such that two CC pumps and one CC heat exchanger are available for use, and two heat exchangers serve as shared standby units. The CC surge tank accommodates expansion, contraction and in-leakage of water. A radiation monitor in the CC System return header closes the surge tank vent valve (if open) in the unlikely event that the radiation level reaches a preset level above the normal background. Potassium Chromate is added to the CC loops to prevent corrosion. The Component Cooling Water System is in continuous service during normal plant operation.

The in-scope portion of the CC System is the SR components up to and including the valves that can be remotely isolated from the NSR portions of the CC System. This includes pumps, HXs, tanks, piping and valves. Two short sections of the NSR CC System piping are also included in-scope for Criterion 2.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Component Cooling Water System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Station Blackout, and Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Component Cooling Water System containing components subject to an AMR extend from the supply header to the return header, and include pumps, heat exchangers, equipment coolers, surge tanks, piping and valves.

The following fluid systems interface with the Component Cooling Water System:

Service Water	Plant Air
Chemical and Volume Control	Non-Class 1 RCS Components
Residual Heat Removal	Class 1 Piping/Components
Safety Injection	Plant Sampling
Containment Spray	Waste Disposal

System Function Listing

A comprehensive listing of functions associated with the Component Cooling Water System, or specific components contained in the system, is provided in the summary below.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide cooling water to the RH, SI, and Containment spray pumps' seal water heat exchangers, and RH heat exchangers.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Containment isolation valves within the Component Cooling Water System perform this primary design system function to prevent the release of radioactivity to the environment.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Provide cooling water to the non-regenerative, excess letdown, RCP seal water, and various other heat exchangers.

Provide cooling water to various radwaste coolers.

Provide decay heat removal from the RC System during cooldown, shutdown, and refueling.

Provide cooling water to the RCP bearing coolers and thermal barriers.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety components in the Component Cooling Water System, whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Component Cooling Water System shall be capable of removing decay heat from the RHR heat exchangers.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Component Cooling Water System contains electrical equipment that is environmentally qualified.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: Portions of the Component Cooling Water System (other than CIVs) perform a Containment isolation function during an SBO.

FSAR Reference

Additional Component Cooling Water System details are provided in Section 5.2 and Section 9.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Component Cooling Water System are listed below:

Unit 1	Unit 2
LR-110E018, Sh. 1	LR-110E029, Sh. 1
LR-110E018, Sh. 2	LR-110E029, Sh. 2
LR-110E018, Sh. 3	LR-110E029, Sh. 3
LR-PBM-230	LR-PBM-230

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-2 along with each Component Group’s intended function(s).

Table 2.3.3-2 Component Cooling Water System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW ELEMENTS	PRESSURE BOUNDARY
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RADIATION MONITOR	PRESSURE BOUNDARY
TANKS	PRESSURE BOUNDARY
THERMOWELLS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.3 Spent Fuel Cooling System

System Description

The Spent Fuel Cooling System is designed to remove decay heat produced by irradiated fuel assemblies stored in the spent fuel pool (SFP). The Spent Fuel Cooling (SF) System consists of two separate trains, with a common suction and return header, each having an identical heat exchanger and pump, and the associated piping and valves to support the system intended functions. Water from the pool is pumped through one or both heat exchangers for cooling and returned to the pool. When purification is required, a portion of the flow is diverted through the interconnecting SF purification sub-system. Service Water is provided to the heat exchangers for removal of decay heat, although SW can be interrupted during accident conditions. Portions of the SF System are credited for use in safe shutdown following some plant fires (Fire Protection).

The SF System piping is arranged such that failure of any piping does not drain the SFP. To protect against the possibility of a complete loss of water in the SFP, the suction line terminates near the top of the pool. The SF System cooling water return line, which terminates lower in the pool, contains a siphon break line near the normal SFP water level such that the pool water cannot be siphoned. In the event of a complete failure of the cooling system for a long period of time, the fuel pool water inventory can be maintained with fire suppression sub-system water.

The SF System is normally in continuous service during normal plant operation.

The in-scope portion of the SF System consists of the main cooling loops, including the pumps, HXs, piping and valves. Some of the NSR branch piping is also in-scope for Criterion 2.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Spent Fuel Cooling System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Spent Fuel Cooling System containing components subject to an AMR extend from the suction header to the return header and include the pumps, heat exchangers, piping and valves (including the fuel transfer tube isolation valves).

The following mechanical systems interface with the Spent Fuel Cooling System:

Safety Injection	CVCS
Service Water	Waste Disposal
Fire Protection	

System Function Listing

A comprehensive listing of functions associated with the Spent Fuel Cooling System, or specific components contained in the system, is provided in the summary below.

Code P	Cri 1	Cri 2	Cri 3				
ENSURE ADEQUATE COOLING IN THE SPENT FUEL POOL			FP	EQ	PTS	AT	SB
	X						

Comment: The Spent Fuel Cooling System removes the decay heat produced by irradiated fuel assemblies stored in the spent fuel pool.

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: Provide radiation shielding for protection of personnel working in the area of the spent fuel pool.

Clarify the spent fuel storage pool and transfer canal water by purification, particulate removal, and surface skimming.

Code Y	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety components in the Spent Fuel Cooling System whose failure could affect safety related systems.

Code Z1	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)			FP	EQ	PTS	AT	SB
			X				

Comment: Components within the Spent Fuel Cooling System provide pressure boundary functions that are required in a safe shutdown fire protection scenario.

FSAR Reference

Additional Spent Fuel Cooling System details are provided in Section 9.9 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Spent Fuel Cooling System are listed below:

Common
LR-110E018, Sh. 4

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-3 along with each Component Group's intended function(s).

Table 2.3.3-3 Spent Fuel Cooling System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW ELEMENT	PRESSURE BOUNDARY
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.4 Waste Disposal System

System Description

The Waste Disposal System provides all the equipment necessary to collect, process, and prepare for disposal all potentially radioactive liquid, gaseous, and solid wastes produced as a result of plant operation. Radioactive fluids entering the Waste Disposal System (WD) are collected in sumps and tanks until determination of subsequent treatment methods can be made. Design of the WD System is based on assuring that the consequences of a radioactive release from a sub-system or component do not pose a hazard to public health and safety. The Waste Disposal System contains Environmentally Qualified (EQ) components.

The principal components of the WD System within the scope of License Renewal are the waste gas and waste liquid containment penetration isolation components, Waste Disposal System heat exchangers with Component Cooling Water interfaces, the associated piping and valves to support the system intended functions. Some components are credited at PBNP for flood control, and Service Water System isolation from Waste Disposal System components.

Portions of the Waste Disposal System are either in continuous or intermittent operation during normal plant operation.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Waste Disposal System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Waste Disposal System containing components subject to an AMR include the waste gas and waste liquid containment penetration isolation components, Waste Disposal System heat exchangers with CCW interfaces, and the essential piping and valves credited at Point Beach for flood controls and Service Water System isolation from Waste Disposal System components.

The following fluid systems interface with the Waste Disposal System:

Non-Class 1 RCS Components	Component Cooling Water
Residual Heat Removal	Service Water
Chemical and Volume Control	Plant Air

System Function Listing

A comprehensive listing of functions associated with the Waste Disposal System, or specific components contained in the system, is provided in the summary below.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The waste gas seal water heat exchangers within the Waste Disposal System perform this associated design system function.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Isolation valves within the Waste Disposal System perform this associated design system function for Containment isolation.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Waste Disposal System provides:

1. for gas removal, processing, decay, and storage
2. hydrogen gas for main generator cooling and make-up due to leakage from the main generators
3. nitrogen to various tanks for blanketing, purging, and level indication
4. for receipt, processing, and storage of radioactive or potentially radioactive wastes

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety components in the Waste Disposal System whose failure could affect safety related systems.

Additional valves are included for flood protection considerations.

Code Z2	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)			FP	EQ	PTS	AT	SB
				X			

Comment: The Waste Disposal System contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Waste Disposal System details are provided in Section 5.2, Section 11.1, Section 11.2, and Section 11.3 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Waste Disposal System are listed below:

Unit 1
LR-684J971, Sh. 1
LR-684J971, Sh. 1A
LR-684J971, Sh. 2

Unit 2
LR-684J971, Sh. 1
LR-684J971, Sh. 1A
LR-684J971, Sh. 2
LR-684J972, Sh. 1

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-4 along with each Component Group's intended function(s).

Table 2.3.3-4 Waste Disposal System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW INDICATORS	PRESSURE BOUNDARY
HEAT EXCHANGER	PRESSURE BOUNDARY
INSTRUMENTATION	PRESSURE BOUNDARY

Table 2.3.3-4 Waste Disposal System

Component Group	Intended Function
PIPING AND FITTINGS	PRESSURE BOUNDARY
RADIATION MONITOR	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.5 Service Water System

System Description

The Service Water System provides cooling water to various essential and non-essential services throughout the plant. The six motor-driven Service Water (SW) pumps take their suction from the pump bays in the Circulating Water (CW) Pump House (raw water from Lake Michigan) and discharge into a loop supply header. This supply header is capable of being split (via isolation valves) into two (2) separate headers. Essential services are capable of being supplied from either header. Non-essential services are capable of being automatically isolated from the supply headers. The return lines discharge to the CW discharge in either Unit 1 and/or Unit 2. Under the conditions of a loss-of-coolant accident (LOCA), the SW System is capable of providing the necessary cooling capacity for the essential loads for the affected unit and supply SW for the normal operation of the unaffected unit. This is the most limiting heat load for the SW System. The Service Water System is credited for use in safe shutdown following some plant fires (Fire Protection).

The supply of SW for essential services is redundant and can be maintained in case of failure of one header. The SW System supplies the following essential loads (note that the associated cooler/heat exchanger is addressed in its respective system):

- PAB Battery Room coolers (Essential Ventilation)
- Emergency diesel generator (G01 and G02) engine coolant heat exchanger (Emergency Power)
- Component Cooling Water (CC) heat exchangers (Component Cooling)
- Containment ventilation coolers (accident fan coolers) (Containment Ventilation)

- Turbine-driven Auxiliary Feedwater Pumps (pump suction supply and turbine bearing coolers) (Auxiliary Feedwater)
- Motor-driven Auxiliary Feedwater Pumps (pump suction supply) (Service Water)
- Containment ventilation fan motor coolers (Containment Ventilation)

The SW System is considered a closed system inside Containment. The SW System provides cooling water to the Spent Fuel Pool (SF) heat exchangers for spent fuel decay heat removal, although this is a non-essential load. The SW System is also capable of supplying long-term makeup water to the suction of the Auxiliary Feedwater (AF) pumps when the normal makeup source from the Condensate Storage Tanks is unavailable. The SW System supplies water for the Fire Protection (FP) sprinkler systems in the EDG (G01 and G02) rooms and for the fire hose reels within Containment. Many non-essential (NSR) loads are supplied by SW System, but are capable of being automatically isolated during accident conditions.

The SW System is periodically treated to control biological fouling, including the recent installation of a copper ion injection sub-system. The SW System includes the pumps, strainers, heat exchangers, and the associated piping and valves to support the system intended functions. The Service Water System is normally in service during plant operation and shutdown.

The in-scope portion of the SW System consists of the SR portions of supply and return headers, including the pumps, HXs, piping and valves. Much of the SW return header is NSR, but was included in-scope up to manual isolation valves, per Criterion 2.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Service Water System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Service Water System containing components subject to an AMR extend from pump bays to the CW discharge, including connections to the suction of the Auxiliary Feedwater pumps, or the Fire Protection System; and includes pumps, heat exchangers, strainers, piping and valves.

The following fluid systems interface with the Service Water System:

Auxiliary Feedwater	Spent Fuel Cooling
Essential Ventilation	Plant Air
Containment Ventilation	Component Cooling Water
Emergency Power	Fire Protection

System Function Listing

A comprehensive listing of functions associated with the Service Water System, or specific components contained in the system, is provided in the summary below.

Code H PROVIDE EMERGENCY HEAT REMOVAL FROM THE REACTOR COOLANT SYSTEM USING SECONDARY HEAT REMOVAL CAPABILITY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide emergency supply of water to the auxiliary feedwater pumps when the normal condensate (CS) supply is exhausted.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide safety related cooling water for various plant HXs:

1. component cooling water (CC) HXs (for RHR post-accident heat loads, and RHR/SI seal water HXs)
2. diesel generator (DG) coolant heat exchangers
3. Containment cooler fan motor HXs
4. bearing coolers on TDAFW pumps

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Containment isolation valves within the Service Water System perform this primary design system function to prevent the release of radioactivity to the environment. Service Water is a closed system inside Containment.

Code L PROVIDE EMERGENCY HEAT REMOVAL FROM PRIMARY CONTAINMENT AND PROVIDE CONTAINMENT PRESSURE CONTROL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide cooling water to the accident fan coolers (Containment Ventilation System).

Code O MAINTAIN EMERGENCY TEMPERATURES WITHIN AREAS CONTAINING SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide cooling water to the PAB battery room HVAC heat exchangers (Essential Ventilation System).

Code P ENSURE ADEQUATE COOLING IN THE SPENT FUEL POOL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide cooling water to the spent fuel pool cooling water (SF) heat exchangers for decay heat removal.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The SW System provides cooling water to various non-safety related plant loads.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety related components in the Service Water System whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Service Water System shall be capable of providing:

1. cooling of the component cooling water heat exchangers and the auxiliary feedwater pump bearings to support reactor heat removal
2. a back-up water supply to the auxiliary feedwater pumps to support reactor heat removal
3. cooling of the emergency diesel generators to support supplying power to safe shutdown systems and components
4. a back-up water supply to the emergency diesel generator room sprinklers and the fire protection hose reels in Containment.

FSAR Reference

Additional Service Water System details are provided in Section 5.2, Section 6.3, Section 9.6, and Section 9.9 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Service Water System are listed below:

Unit 1	Unit 2
LR-M-201, Sh. 3	LR-M-2201, Sh. 3
LR-M-207, Sh. 1	LR-M-2207, Sh. 1
LR-M-207, Sh. 1A	LR-M-2207, Sh. 2
LR-M-207, Sh. 2	
LR-M-207, Sh. 3	
LR-M-207, Sh. 4	

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-5 along with each Component Group's intended function(s).

Table 2.3.3-5 Service Water System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
EXPANSION JOINTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY PROVIDE FILTRATION
FLOW ELEMENTS	PRESSURE BOUNDARY
FLOW INDICATORS	PRESSURE BOUNDARY
HEAT EXCHANGER	PRESSURE BOUNDARY

Table 2.3.3-5 Service Water System

Component Group	Intended Function
HEATERS/COOLERS	HEAT TRANSFER PRESSURE BOUNDARY
HOSE REEL	PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RADIATION MONITOR	PRESSURE BOUNDARY
RESTRICTING ORIFICES	PRESSURE BOUNDARY RESTRICTS FLOW
SIGHT GLASS	PRESSURE BOUNDARY
THERMOWELLS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.6 Fire Protection System

System Description

The Fire Protection System is to provide assurance, through defense-in-depth design, that a fire will not prevent the performance of necessary safe-shutdown functions, or significantly increase the risk of radioactive release to the environment, during a postulated fire. The Fire Protection (FP) System provides fire suppression by fixed water spray and sprinkler systems, fixed gas systems, hose stations, and portable extinguishers located in various areas of the PBNP site. PBNP has a fire detection and alarm sub-system that alarms locally in selected areas of the plant and transmits various alarm, supervisory, and trouble signals to the Control Room. In addition to ensuring compliance with the regulations (regulated event) for Fire Protection, components within the Fire Protection System (FP) are also credited for use in safe shutdown following Station Blackout (SBO) events. The FP System receives its water supply from Lake Michigan.

The FP System also provides alternate sources of backup water to other plant systems. The FP System supports SBO activities by providing a backup supply of bearing cooling water to the turbine-driven Auxiliary Feedwater pumps. It can also provide a backup source of water inventory to the Spent Fuel Pool, or a backup supply of feedwater through the use of the diesel-driven fire pump and routing of a fire hose between existing connections on the fire header and the Condensate Storage Tanks. These secondary functions of the FP System do not prohibit the system from performing its primary functions.

The principal components of the FP System are the main firewater loop, a diesel-driven and motor-driven fire pump, jockey pump, accumulator, hose stations, hydrants, hoses, spray/sprinkler heads, nozzles, fuel oil day-tank, fuel oil supply to the diesel-driven fire pump, and the associated piping and valves to support the system functions. Also included are two fixed Halon gas suppression systems and the required gas cylinders, nozzles, and the associated piping and valves to support the Halon sub-system's intended functions.

Additionally, the FP System includes the Reactor Coolant Pump (RCP) Oil Collection sub-system that contains leakage from the RCPs' lubricating oil sub-system to reduce the possibility of a fire in accordance with the requirements of Appendix R. The principal components of the RCP Oil Collection sub-system are the enclosures, drip pans, covers, oil collection tanks, piping, and valves.

Please note that some components in this system are considered consumables. These components and their disposition are discussed in Section 2.1.3.1.3.

The Appendix R safe shutdown function applies to the FP System components that provide for safe shutdown of the plant in the event of a severe fire. Appendix R components not specifically residing within the FP System, are addressed within the individual systems for those components.

The FP components which (a) do not provide fire suppression capabilities for safety related equipment or for equipment relied on for compliance with the regulations identified in the 10 CFR 54 scoping criteria, or (b) whose failure will not prevent the satisfactory performance of a safety related function, are not included in the scope of License Renewal. The portions of the Fire Protection System that are excluded from the scope of License Renewal are remote and outside the protected area and include the following:

- NES Office Building /Training Building - isolable from the FP System by a post indicating valve
- EIC (Energy Information Center) - not connected to the FP System (no fire suppression)
- SBCC (Site Boundary Control Center) - not connected to the FP System (separate fire suppression equipment)

Those structural commodities such as fire damper housings, fire doors, penetration seals, etc., are addressed in the structural section of the LRA. Additionally, fire detection and alarm devices are active components and do not require an AMR. The Fire Protection System is a standby system during normal plant operation.

Since some SSCs in the Fire Protection System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Fire Protection System subject to an AMR include pumps, piping, valves, accumulator, hose stations, hydrants, spray/sprinkler heads, nozzles, fuel oil day-tank, fuel oil supply to the diesel-driven fire pump, Halon gas cylinders, and RCP Oil Collection components.

The following fluid systems interface with the Fire Protection System:

Spent Fuel Cooling	Plant Air
Auxiliary Feedwater	Emergency Power
Service Water	Non-Class 1 RCS Components

System Function Listing

A comprehensive listing of functions associated with the Fire Protection System, or specific components contained in the system, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: In the event of complete failure of the cooling system for a long period of time, the fuel pool water inventory can be maintained with fire suppression sub-system water.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety related components in the Fire Protection System whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Fire Protection System shall be capable of providing:

1. automatic and manual fire suppression and detection capability in various locations throughout the plant
2. portable ventilation in various locations throughout the plant
3. portable smoke ejectors in various locations throughout the plant

The Fire Protection System shall have sufficient fire protection capability to withstand the hazards associated with the defined Fire Areas and prevent the spread of fire outside of the Fire Area.

The Fire Protection System shall have an RCP Oil Collection sub-system to reduce the possibility of fire from RCP lube oil.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The Fire Protection System shall be capable of providing cooling of the auxiliary feedwater pump bearings to support reactor heat removal.

FSAR Reference

Additional Fire Protection System details are provided in Section 9.9, Section 9.10, and Section 10.2 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Fire Protection System are listed below:

<u>Common</u>	<u>Common</u>
LR-M-208, Sh. 1	LR-M-208, Sh. 9
LR-M-208, Sh. 2	LR-M-208, Sh. 10
LR-M-208, Sh. 4	LR-M-208, Sh. 11
LR-M-208, Sh. 5	LR-M-208, Sh. 12
LR-M-208, Sh. 6	LR-M-208, Sh. 13
LR-M-208, Sh. 7	LR-M-208, Sh. 14
LR-M-208, Sh. 8	LR-M-208, Sh. 15

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-6 along with each Component Group's intended function(s).

Table 2.3.3-6 Fire Protection System

Component Group	Intended Function
ACCUMULATORS/CYLINDERS	PRESSURE BOUNDARY
COMPRESSOR CASING	PRESSURE BOUNDARY
CS COMPONENTS	PRESSURE BOUNDARY
EXPANSION JOINTS	PRESSURE BOUNDARY

Table 2.3.3-6 Fire Protection System

Component Group	Intended Function
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY PROVIDE FILTRATION
FIRE HYDRANT	PRESSURE BOUNDARY
FLAME ARRESTORS	FLAME SUPPRESSION
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
HOSE REEL	PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RCP OIL COLLECTION	PRESSURE BOUNDARY
SIGHT GLASS	PRESSURE BOUNDARY
SPRAY NOZZLES	FLOW CONTROL PRESSURE BOUNDARY
SPRINKLER HEADS	FLOW CONTROL PRESSURE BOUNDARY
TANKS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.7 Heating Steam System - Within Scope of License Renewal for Criterion 2 Only

System Description

The Heating Steam System supports habitability and equipment reliability by maintaining plant area temperatures within acceptable bounds. In addition to supporting ventilation functions, the Heating Steam System also provides process steam for other plant support functions. The principal components of the Heating Steam System are the boiler, tanks, pumps, heaters and associated piping and valves. The heating steam is provided from the house boilers or from a connection in the Main and Auxiliary Steam System.

The Heating Steam System does not perform any safety related functions. However, certain portions of the Heating Steam System are in-scope for License Renewal in accordance with 10 CFR 54.4(a)(2) and the NRC's associated ISG. This methodology is further explained in Section 2.1.2.1.2 of the LRA.

All heating steam piping and heating steam condensate return piping in the Primary Auxiliary Building (PAB) was conservatively included in-scope due to its proximity to numerous safety related components. Therefore, all heating steam supply and condensate return piping, and their associated components, in the PAB are in-scope. However, a number of components are isolated and abandoned-in-place and, therefore, the scoping boundary stops at the normally isolated valve.

Heating steam was previously supplied to and penetrated the Containment. These connections have since been capped and welded and are addressed in the Containment Isolation Components System.

The description above results in some non-safety related SSCs in this system, whose failure could affect the capability of a SR SSC to perform its safety function, as being considered in-scope in accordance with 10 CFR 54.4(a)(2).

The portions of the Heating Steam System containing components subject to an AMR include the heating steam supply and condensate return piping in the PAB, including heat exchangers, piping and valves.

The following fluid systems interface with the Heating Steam System:

N/A - Criterion 2 Only

System Function Listing

A comprehensive listing of functions associated with the Heating Steam System, or specific components contained in the system, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Provide heating steam to HVAC and miscellaneous components.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: Portions of the non-safety related Heating Steam System in the PAB have the potential to affect the function of safety related equipment.

FSAR Reference

None.

License Renewal Drawings

The license renewal drawings for the Heating Steam System are listed below:

Unit 1
LR-M-214, Sh. 1
LR-M-214, Sh. 2
LR-M-2214

Unit 2
LR-M-214, Sh. 1
LR-M-2214

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-7 along with each Component Group’s intended function(s).

Table 2.3.3-7 Heating Steam System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY

Table 2.3.3-7 Heating Steam System

Component Group	Intended Function
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY
HEATERS/COOLERS	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
STEAM TRAPS	PRESSURE BOUNDARY
TANKS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.8 Emergency Power System

System Description

The Emergency Power System is designed to provide emergency/backup power to the station, in the event of a loss of normal power. The Emergency Power System consists of four diesel generators and a gas turbine generator. The normal source of power to the safety related 4160 VAC and 480 VAC buses is from offsite power through the station low voltage auxiliary transformers. If this normal source fails, the standby source of power is the emergency Diesel Generators (DG). The DG portion of the Emergency Power System is composed of four diesel generators that directly supply the safety related 4160 VAC Power System. In the unlikely event of a loss of all offsite and onsite AC power, the Gas Turbine (GT) generator is available to power the required loads until a DG or offsite power is restored. The Emergency Power System contains components credited for use in safe shutdown following Station Blackout (SBO) events and some plant fires (Fire Protection).

The four diesel generators are divided into two trains, 'A' and 'B'. Each emergency diesel generator is capable of sequentially starting and supplying the power requirements of one complete set of safeguards equipment for one unit and providing sufficient power to allow the second unit to be placed in a safe shutdown condition. This provides the necessary power to cool the core and maintain the Containment pressure within the design value for a loss-of-coolant accident (coincident with a loss of offsite power) in addition to supplying sufficient power to shut down the unaffected unit. The Emergency Power System is a standby system during normal plant operation.

Each DG engine is equipped with a turbocharger, and air start, intake/exhaust air, lube oil, cooling water, fuel oil, and ventilation sub-systems to support system intended functions. (Ventilation is addressed in the Essential Ventilation System.) The Gas Turbine is provided with a starting diesel, auxiliary power supply diesel, and lube oil, cooling air, cooling water, and fuel oil sub-systems, to support system intended functions. The Emergency Power support sub-systems include all components up to the EDG engine power blocks and GT power block. The DG and GT power blocks and components within the power blocks are considered complex assemblies (active components) and not subject to an AMR. The DG and GT, along with their associated support sub-systems, are in-scope of License Renewal.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Emergency Power System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Emergency Power System subject to an AMR are the DG and GT sub-systems, including turbochargers, tanks, expansion joints, heat exchangers, piping and valves.

The following fluid systems interface with the Emergency Power System:

Service Water	Plant Air

System Function Listing

A comprehensive listing of functions associated with the Emergency Power System, or specific components contained in the system, is provided in the summary below.

Code D SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: G01 (G02) EDG/Fuel Transfer System Fuel Oil Transfer switches provide input to the ESFAS.

Code Q PROVIDE ELECTRICAL POWER TO SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provides emergency power to the safety related 4160 VAC Power System.

Code S SPECIAL CAPABILITY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: During accidents, portions of the Emergency Power System provide signals for RG 1.97 Type D post-accident monitoring variables.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: Components within the Emergency Power System have the potential to affect safety related equipment.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The emergency diesel generators shall be capable of providing power to the electrical distribution system supplying safe shutdown systems and components.

The gas turbine generators shall be capable of providing power to the electrical distribution system supplying safe shutdown systems and components.

The fuel oil sub-system shall be capable of supplying fuel oil to the emergency diesel generators and the gas turbine to support supplying power to safe shutdown systems.

The diesel starting air sub-system shall be capable of starting the emergency diesel generators to support supplying power to safe shutdown systems.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The emergency diesel generators shall be capable of providing power to the electrical distribution system supplying safe shutdown systems and components.

The gas turbine generators shall be capable of providing power to the electrical distribution system supplying safe shutdown systems and components.

The fuel oil sub-system shall be capable of supplying fuel oil to the emergency diesel generators and the gas turbine to support supplying power to safe shutdown systems.

The diesel starting air sub-system shall be capable of starting the emergency diesel generators to support supplying power to safe shutdown systems.

FSAR Reference

Additional Emergency Power System details are provided in Section 8.0, Section 8.8, and Section 8.9 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Emergency Power System are listed below:

Common
LR-M-209, Sh. 12
LR-M-209, Sh. 14
LR-M-209, Sh. 15
LR-M-219, Sh. 1
LR-M-219, Sh. 2
LR-M-219, Sh. 3
MKW 6090F03001 Sh.1
MKW 6090F04001 Sh. 1

Common
LR-M-226, Sh. 2
LR-M-227, Sh. 1
LR-M-227, Sh. 2
Figure 12.2.3 (GT TM)
Figure 12.2.4 (GT TM)
Figure 12.2.5 (GT TM)
Figure 12.2.6 (GT TM)
LR-M-226, Sh. 1

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-8 along with each Component Group's intended function(s).

Table 2.3.3-8 Emergency Power System

Component Group	Intended Function
AIR MOTOR	PRESSURE BOUNDARY
DRAIN TRAP	PRESSURE BOUNDARY
EXPANSION JOINTS	PRESSURE BOUNDARY
FAN/BLOWER HOUSING	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY PROVIDE FILTRATION
FLAME ARRESTORS	FLAME SUPPRESSION
FLOW ELEMENTS	PRESSURE BOUNDARY
FLOW INDICATOR	PRESSURE BOUNDARY

Table 2.3.3-8 Emergency Power System

Component Group	Intended Function
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
HEATERS/COOLERS	HEAT TRANSFER PRESSURE BOUNDARY
INSTRUMENTATION	PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RESTRICTING ORIFICES	PRESSURE BOUNDARY RESTRICTS FLOW
SIGHT GLASS	PRESSURE BOUNDARY
SILENCER	PRESSURE BOUNDARY
TANKS	PRESSURE BOUNDARY
TURBINE CASING	PRESSURE BOUNDARY
TURBO-CHARGER	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.9 Containment Ventilation System

System Description

The Containment Ventilation System provides for emergency heat removal from the Containment atmosphere, Containment pressure control, and Containment isolation. The Containment Ventilation System contains Environmentally Qualified (EQ) components.

The Containment Ventilation System is made up of the following heating and ventilating sub-systems:

Containment Cooling sub-system (VNCC)

Containment Purge Supply and Exhaust sub-system (VNPSE)

Control Rod Drive (CRDM) Cooling sub-system (VNCRD)

Reactor Cavity Cooling sub-system (VNRC)

Refueling Cavity Ventilation sub-system (VNRF)

Containment Cleanup sub-system (VNCF)

(The Post Accident Containment Ventilation sub-system (PACV) is addressed separately in the Containment Hydrogen Detectors and Recombiner System.)

Of these sub-systems, only VNCC and VNPSE are in-scope for License Renewal. The other sub-systems were reviewed and determined not to be in-scope due to having no License Renewal Intended Function.

Containment Cooling Sub-system

The principal components of the Containment Cooling sub-system include filters, fans, dampers, heat exchangers, ductwork and the associated piping and valves to support the system intended functions. Each air-cooling unit consists of an inlet screen, roughing filter, cooling coil, vane axial fans, back draft damper housings, and a discharge header that is common to all four units. Roughing filters are installed during refueling outages when a significant potential for a dusty Containment atmosphere exists. Each cooling coil in an air-handling unit transfers heat to the Service Water System during normal plant operation and for limiting design basis accident conditions. In the event of a loss-of-coolant accident, these cooling units have sufficient capacity to maintain the Containment pressure within design limits.

The fans, motors, electrical connections and all other equipment in the Containment necessary for operation of the system under accident conditions are capable of operating under the environmental conditions existing following a loss-of-coolant accident. The Containment Cooling sub-system is in service during normal plant operation and design basis accident conditions.

Containment Purge Supply and Exhaust Sub-system

This Containment Purge Supply and Exhaust sub-system is independent of any other system and includes provisions to both supply and exhaust air from the Containment. Purging of the Containment is prohibited unless the reactor is in the cold shutdown mode due to Containment isolation criteria. That portion of the Containment Purge sub-system requiring an AMR includes the inboard and outboard Containment isolation valves, and associated piping and valves to support the system intended function.

The Containment ventilation ductwork, fans (except the refueling cavity supply and exhaust fans), filters, coils, and housings within the Containment are designed as seismic Class I.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Containment Ventilation Systems containing components subject to an AMR include the equipment necessary to provide emergency heat removal from the containment atmosphere and containment pressure control, and equipment necessary for containment isolation; including heat exchangers, ductwork, damper housings, piping and valves.

The following fluid systems interface with the Containment Ventilation System:

Service Water	Plant Air

System Function Listing

A comprehensive listing of functions associated with the Containment Ventilation System, or specific components contained in the system, is provided in the summary below.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Containment isolation valves within the VNPSE sub-system perform this primary design system function to prevent the release of radioactivity to the environment. The cooling coils for the VNCC sub-system are part of the Service Water System, which is a closed system inside Containment, and therefore are also included as performing this system intended function.

Code L PROVIDE EMERGENCY HEAT REMOVAL FROM PRIMARY CONTAINMENT AND PROVIDE CONTAINMENT PRESSURE CONTROL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The VNCC sub-system removes heat from the Containment following a LOCA or MSLB to limit Containment pressure/temperature to less than the design limits.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The VNRC sub-system removes heat generated by neutron and gamma radiation during operation from the primary shield and reactor vessel support structure.

The VNPSE sub-system provides ventilation during refueling for continuous personnel access and maintains negative pressure.

The VNCC sub-system maintains Containment ambient temperature within specified limits during normal operations.

The VNCC sub-system provides for RC leakage detection via humidity transmitters.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The VNCC and VNPSE sub-systems contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Containment Ventilation System details are provided in Section 5.2, Section 5.3, and Section 6.3 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Containment Ventilation System are listed below:

Unit 1	Unit 2
LR-M-215, Sh. 1	LR-M-2215, Sh. 1
LR-PBM-332	LR-PBM-2332

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-9 along with each Component Group's intended function(s).

Table 2.3.3-9 Containment Ventilation System

Component Group	Intended Function
ACCUMULATORS/CYLINDERS	PRESSURE BOUNDARY
CS COMPONENTS	PRESSURE BOUNDARY
DAMPER HOUSINGS	PRESSURE BOUNDARY
DUCTWORK	PRESSURE BOUNDARY
FAN/BLOWER HOUSING	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
HEATERS/COOLERS	HEAT TRANSFER PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
THERMOWELLS	PRESSURE BOUNDARY
VALVE BODY	PRESSURE BOUNDARY

2.3.3.10 Essential Ventilation System

System Description

The Essential Ventilation System is made up of the following sub-systems that provide heating, ventilation, and air conditioning (including chilled water) for their respective areas and associated equipment contained within those areas:

- Control Room Ventilation sub-system (VNCR)
- Computer Room Ventilation sub-system (VNCOMP)
- Cable Spreading Room Ventilation sub-system (VNCSR)
- PAB Battery and Inverter Room Ventilation sub-system (VNBI)
- Diesel Generator Building Ventilation sub-system (VNDG)
- Primary Auxiliary Building Ventilation sub-system (VNPAB)
- Circ Water Pump House Ventilation sub-system (VNPH)
- Radwaste Ventilation sub-system (VNRAD)
- Drumming Area Ventilation sub-system (VNDRM)
- Battery Room Ventilation sub-system (VNBR)
- Aux. Feedwater Area Ventilation sub-system (VNAFW)
- Gas Turbine Building Ventilation sub-system (VNGT)

Of these sub-systems, only VNCR, VNCOMP, VNCSR, VNBI, VNGT, VNPAB, and VNDG are in-scope for License Renewal. The other sub-systems were reviewed and determined not to be in-scope due to no License Renewal Intended Function.

Control Room/Computer Room/Cable Spreading Room Ventilation sub-systems

These three sub-systems are interrelated and discussed together. The VNCR, VNCOMP, and VNCSR (for isolation points only) sub-systems provide radiological habitability for the Control and Computer Rooms, which are both within the Control Room envelope. For radiological habitability, the sub-systems are capable of operating in four different modes providing for Control Room pressurization to limit in-leakage, makeup and recirculation through HEPA and charcoal filters to remove contaminates, and recirculation without filtration or makeup.

The sub-systems also provide the capability to exhaust smoke from the Control Room, Computer Room, or Cable Spreading Room through a dedicated smoke and heat vent fan.

PAB Battery and Inverter Room Ventilation sub-system

The VNBI sub-system controls the PAB battery room temperatures to maintain the station batteries, inverters, and other safety related components within safe operating temperature limits, including during plant fires (Fire Protection). The VNBI sub-system is classified as seismic Class I.

Gas Turbine Building Ventilation sub-system

The VNGT sub-system is required to support the operation of the gas turbine by providing cooling (via air flow) once the gas turbine equipment is in operation. These functions are necessary for both Appendix R and SBO scenarios.

Diesel Generator Building Ventilation sub-system

The VNDG sub-system maintains ambient temperatures in the required areas within acceptable limits to support the operation of G01, G02, G03, and G04 during a design basis accident, loss of offsite power, Station Blackout (SBO) events, and some plant fires (Fire Protection). G03/G04 draw outside air for combustion rather than room air like the G01/G02 diesel generators. The sub-system provides combustion and ventilation air to the emergency Diesel Generator room to maintain the room within operating temperature and pressure limits. The VNDG sub-system is classified as seismic Class I.

Primary Auxiliary Building Ventilation Sub-system

Portions of the VNPAB sub-system are used to maintain mild room environments in some post-HELB scenarios (non-safety affecting safety).

Those structural commodities such as fire damper housings are addressed in the structural aging management section of the LRA.

The Essential Ventilation System contains components that are credited for use in safe shutdown following Station Blackout (SBO) events and some plant fires (Fire Protection).

The Essential Ventilation System is normally in either continuous or intermittent operation during normal plant operation and shutdown and certain design basis accident conditions.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Essential Ventilation System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Essential Ventilation System containing components subject to an AMR include filters, fans, damper housings, valves, heat exchangers, air conditioning/chiller packages, ductwork, and the associated piping and valves to support the system intended functions.

The following fluid systems interface with the Essential Ventilation System:

Service Water	Plant Air

System Function Listing

A comprehensive listing of functions associated with the Essential Ventilation System, or specific components contained in the system, is provided in the summary below.

Code O MAINTAIN EMERGENCY TEMPERATURES WITHIN AREAS CONTAINING SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide environmental climate control to the inverter and station battery rooms for the VNBI sub-system.

Provide cooling to the EDG rooms when the EDGs are operating to maintain environmental limits for equipment, provide combustion air to the EDGs, and provide ventilation to support operation of the EDGs during DBAs for the VNDG sub-system.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Provide ventilation to prevent hydrogen buildup in the battery rooms for the VNBI sub-system.

Maintain temperatures within specified limits to provide for equipment operability for the VNCOMP, VNCR, VNCSR, and VNPAB sub-systems.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety components in the VNBI, VNCOMP, VNDG, and VNPAB sub-system whose failure could affect safety related systems.

Maintain control room envelope to limit unfiltered leakage for the VNCOMP, VNCR, and VNCSR sub-systems and, filter and remove particulate and iodine from the outside air during emergency operations to support control room occupancy.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The VNCOMP, VNCR, and VNCSR sub-systems shall be capable of full recirculation operation and smoke exhaust capability.

The VNDG sub-system shall be capable of providing cooling (via air flow) of the rooms housing the emergency diesel generators (G01/02).

The VNGT sub-system shall be capable of providing cooling (via air flow) for components associated with the gas turbine (G05).

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The VNDG sub-system shall be capable of providing cooling (via air flow) of the rooms housing the emergency diesel generator which is relied upon as the Alternate AC source.

The VNGT sub-system shall be capable of providing cooling (via air flow) for components associated with the gas turbine (G05).

FSAR Reference

Additional Essential Ventilation System details are provided in Section 8.7, Section 8.8, Section 9.5, and Section 9.8 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Essential Ventilation System are listed below:

Common
LR-M-143
LR-M-144, Sh. 1
LR-M-144, Sh. 2
LR-M-144, Sh. 3

Common
LR-M-211, Sh. 3
LR-M-214, Sh. 4
LR-PBM-250

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-10 along with each Component Group's intended function(s).

Table 2.3.3-10 Essential Ventilation System

Component Group	Intended Function
DAMPER HOUSINGS	PRESSURE BOUNDARY
DUCTWORK	PRESSURE BOUNDARY
FAN/BLOWER HOUSING	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY PROVIDE FILTRATION
FLOW ELEMENTS	PRESSURE BOUNDARY
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
HEATERS/COOLERS	HEAT TRANSFER PRESSURE BOUNDARY
HUMIDIFIER	PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
INSTRUMENTATION	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
TANKS	PRESSURE BOUNDARY

Table 2.3.3-10 Essential Ventilation System

Component Group	Intended Function
THERMOWELLS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.11 Treated Water System - Within Scope of License Renewal for Criterion 2 Only

System Description

The Treated Water System is basically comprised of the Water Treatment (WT), Demineralized Water (DI), Potable Water (PW), Hydrazine Addition (HA), Sewage Treatment Plant (STP), and non-radioactive liquid waste disposal (floor drains, secondary sample effluents, etc.) secondary plant sub-systems. These sub-systems treat and demineralize water, store and supply demineralized and potable water for various uses in the plant, transfer and hold sanitary waste and clean site sump discharges, and introduce hydrazine and morpholine to the steam generators and condensate sub-system. The Treated Water System is a non-seismic piping system whose primary function is to support other plant process systems. The principal components of the Treated Water System are pumps, tanks, hot water heaters, hoses, valves and the associated piping.

The Containment isolation valves (CIVs) in the DI sub-system are in-scope for License Renewal, and are addressed in the Containment Isolation Components System. Aside from these components, the Treated Water System does not perform any other safety related function. However, certain portions of the Treated Water System are in-scope for License Renewal in accordance with 10 CFR 54.4(a)(2) and the NRC's associated ISG. This methodology is further explained in Section 2.1.2.1.2.

Portions of the Treated Water System that are considered in-scope include the shear gate valves in the G01/G02 rooms' oily sump, eyewash/safety shower in the Auxiliary Feedwater pump area, equipment drains from the HVAC room above the main Control Room, sump pump discharge piping and STP piping in the SI/CC pump area, DI piping in close proximity to the Containment Spray and Spent Fuel Pool pumps, and DI piping in close proximity to the Unit 2 charging pump cubicles.

The description above results in some non-safety related SSCs in this system, whose failure could affect the capability of a SR SSC to perform its safety function, as being considered in-scope in accordance with 10 CFR 54.4(a)(2).

The portions of the Treated Water System containing components subject to an AMR include the shear gate valves in the G01/G02 rooms oily sump, eyewash/safety shower in the Auxiliary Feedwater pump area, equipment drains from the HVAC room above the main Control Room, sump pump discharge piping and STP piping in the SI/CC pump area, and DI piping in close proximity to the Containment Spray and SFP pumps, and the Unit 2 charging pump cubicles.

The following fluid systems interface with the Treated Water System:

N/A - Criterion 2 Only

System Function Listing

A comprehensive listing of functions associated with the Treated Water System, or specific components contained in the system, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Treat and demineralize water, store and supply demineralized and potable water for various uses in the plant, transfer and hold sanitary waste and clean site sump discharges, and introduce hydrazine and morpholine to the steam generators and condensate sub-system.

Demineralized Water supplies the CC surge tanks and various other plant systems.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: Portions of the NSR Treated Water System whose failure have the potential to affect SR equipment.

FSAR Reference

None.

License Renewal Drawings

The license renewal drawings for the Treated Water System are listed below:

Common	Common
LR-M-223, Sh. 2	LR-PBM-231, Sh. 1
LR-M-223, Sh. 3	LR-PBM-231, Sh. 2

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-11 along with each Component Group's intended function(s).

Table 2.3.3-11 Treated Water System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
PIPING AND FITTINGS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.12 Circulating Water System - Within Scope of License Renewal for Criterion 2 Only

System Description

The Circulating Water System provides a reliable supply of water from Lake Michigan to condense the steam exhausted from the low-pressure turbines. It is a non-seismic piping system whose primary function is to remove heat from the steam cycle via the main condensers. The principal components of the Circulating Water System (CW) are the circulating water pumps, traveling screens and screen wash pumps, chlorine addition sub-system, and the associated piping and valves.

The CW System does not perform any safety related functions. However, certain portions of the CW System are in-scope for License Renewal in accordance with 10 CFR 54.4(a)(2) and the NRC's associated ISG. This methodology is further explained in Section 2.1.2.1.2.

The portion of the Circulating Water System that is in-scope includes the CW pumps, discharge valves, expansion joints and associated piping within the Circulating Water Pumphouse Structure, and the screen wash and chlorination piping and associated components within the Service Water pump room. These are in-scope due to the potential for flooding or spray to affect the function of the safety related service water pumps.

The description above results in some non-safety related SSCs in this system, whose failure could affect the capability of a SR SSC to perform its safety function, as being considered in-scope in accordance with 10 CFR 54.4(a)(2).

The portions of the CW System containing components subject to an AMR include the CW pump casings, valves, expansion joints and associated piping, and the screen wash and chlorination piping, valves, and associated components.

The following fluid systems interface with the Circulating Water System:

N/A - Criterion 2 Only

System Function Listing

A comprehensive listing of functions associated with the Circulating Water System, or specific components contained in the system, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Maintains main condenser vacuum during normal plant operations.

Provides means to prevent biological fouling of main condenser tubes and dechlorination of circulating water discharge.

Provides for ice melt of intake structure by reverse flow of circulating water.

Code Y	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION			FP	EQ	PTS	AT	SB
		X					

Comment: Components within the NSR Circulating Water System whose failure have the potential to affect SR equipment.

FSAR Reference

Additional Circulating Water System details are provided in Section 10.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Circulating Water System are listed below:

Unit 1	Unit 2
LR-M-212, Sh. 1	LR-M-212, Sh. 2
LR-M-212, Sh. 2	LR-M-2212
LR-PBM-232	LR-PBM-232

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-12 along with each Component Group's intended function(s).

Table 2.3.3-12 Circulating Water System

Component Group	Intended Function
EXPANSION JOINTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.13 Fuel Handling System

System Description

The Fuel Handling System provides a safe and effective means of transporting and handling fuel from the time it reaches the plant in an un-irradiated condition until it leaves the plant as spent fuel. The system is designed to minimize the possibility of mishandling or misoperation that could cause fuel damage and potential fission product release.

The principal components of the Fuel Handling System include the fuel manipulator cranes (one in each containment), SFP bridge crane, and the fuel transfer sub-system, consisting of an underwater conveyor that transports fuel assemblies between the reactor cavity and the spent fuel pool and new fuel storage area. Various portions of the Fuel Handling System are shared by both Units l and 2. The only in-scope components in this system are the reactor cavity seal ring, the spent fuel pool (SFP) gates, the new and spent fuel storage racks, and the fuel transfer tube isolation valves.

The refueling cavities are considered part of the containment structure, and the spent fuel pool is considered part of the Primary Auxiliary Building Structure.

Those Fuel Handling System components in-scope for License Renewal and requiring an AMR are addressed in either the structural section of the LRA or in the Spent Fuel Cooling System (fuel transfer tube isolation valves). There are no additional components in the Fuel Handling System evaluation boundary that perform a License Renewal intended function and therefore, no other components are addressed here.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1).

The following fluid systems interface with the Fuel Handling System:

Plant Air	Class 1 Piping/Components
Spent Fuel Cooling	Safety Injection

System Function Listing

A comprehensive listing of functions associated with the Fuel Handling System, or specific components contained in the Fuel Handling System, is provided within the summary below.

Code P ENSURE ADEQUATE COOLING IN THE SPENT FUEL POOL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The SFP gates and fuel transfer tube isolation valves are used as boundaries for the SFP to ensure adequate cooling (by maintaining adequate coolant).

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Fuel Handling System shall provide safe and effective means of replacing, inspecting, modifying, repairing, and performing other similar servicing tasks on fuel assemblies, rod cluster control assemblies (RCCAs), control rod drive shafts (CRDSs), thimble plugs, burnable poison rods, surveillance coupons, and other reactor core inserts and parts commonly serviced by fuel handling equipment in the reactor cavity or spent fuel pool. The Fuel Handling System shall provide reactor core loading and service functions which support requirements for a known, analyzed geometry of fuel material and poison in the reactor core.

FSAR Reference

Additional Fuel Handling System details are provided in Section 9.4 of the FSAR.

License Renewal Drawings

None.

Components Subject to an AMR

Components subject to AMR are addressed in other systems. The component groups for this system that require aging management review are addressed in Table 2.3.3-3, Table 2.4.1-1, and Table 2.4.6-1.

2.3.3.14 Plant Sampling System

System Description

The Plant Sampling System includes both the Primary and Secondary Sampling sub-systems. The Primary Sampling sub-system provides the ability to take samples for laboratory analysis to evaluate reactor coolant and other auxiliary systems' chemistry during normal operation. In addition, this sub-system contains isolation valves for maintaining the Containment pressure boundary. The Secondary Sampling sub-system provides a means to obtain samples from various secondary plant locations for laboratory analysis.

Those portions of the Plant Sampling System that constitute a part of the Containment boundary and reactor coolant pressure boundary are within the ASME Class 1 boundary, and therefore are addressed in the Class 1 Piping/Components System. A few additional in-scope components are addressed in their parent systems for convenience (Residual Heat Removal System, CVCS, and Component Cooling Water System). There are no other components in the Plant Sampling System evaluation boundary that perform a License Renewal intended function and therefore, no other components are addressed here.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection and Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The following fluid systems interface with the Plant Sampling System:

Class 1 Piping/Components	Residual Heat Removal
Chemical and Volume Control	Service Water
Component Cooling Water	Waste Disposal
Plant Air System	Main and Auxiliary Steam
Feedwater and Condensate	

System Function Listing

A comprehensive listing of functions associated with the Plant Sampling System, or specific components contained in the system, is provided in the summary below.

Code E PROVIDE REACTOR COOLANT PRESSURE BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Piping and components within the Plant Sampling system perform this associated design system function to support the safety function of the RC system.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The primary sample and steam generator blowdown sample heat exchangers within the Plant Sampling System perform this associated design system function.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Plant Sampling System provides automatic isolation of sample lines penetrating Containment on a Containment Isolation Signal to prevent the release of radioactivity to the environment.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Plant Sampling System provides capability to remotely obtain fluid samples from the RCS and certain other auxiliary systems for laboratory analysis.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Plant Sampling System shall be capable of isolating RCS to support reactor coolant make-up capability.

Code Z2	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)			FP	EQ	PTS	AT	SB
				X			

Comment: The Plant Sampling System contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Plant Sampling System details are provided in Section 5.2 and Section 9.11.2 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Plant Sampling System are listed below:

Unit 1	Unit 2
LR-541F092	LR-541F448

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.1-1, Table 2.3.2-3, Table 2.3.3-1, and Table 2.3.3-2.

2.3.3.15 Plant Air System

System Description

The Plant Air System includes the Instrument Air (IA), Service Air (SA), and Emergency Breathing Air (EBA) sub-systems. The IA and SA sub-systems supply compressed air throughout the plant. The IA sub-system supplies dry, oil-free air to various components for the normal operation of both units. The SA sub-system supplies non-dried, oil-free air to those plant services not requiring dry air. The EBA sub-system provides emergency breathing air to Control Room personnel based on Fire Protection criteria. The Plant Air System contains Environmentally Qualified (EQ) components and is also credited for use in safe shutdown following Station Blackout (SBO) events and some plant fires (Fire Protection).

The IA sub-system consists of two air compressors, air receivers, air dryer units, and air header piping and valves. The air compressors and aftercoolers are cooled by the Service Water System (SW). Normally one IA compressor is sufficient to supply plant requirements. The Instrument Air sub-system is normally in continuous operation during normal plant operation and shutdown.

In order to maintain operability on loss of IA, some components use nitrogen bottles, regulators, check valves, and/or air accumulators to maintain pressure at a component for varying periods of time to support the License Renewal component intended function (including air to charging pump vari-drives, pressurizer PORVs, purge supply and exhaust boot seals, main steam isolation valves, and auxiliary feedwater discharge and mini-recirc valves).

The in-scope portion of the IA sub-system includes those IA components that support the charging pump varidrives, pressurizer PORVs, and the IA Containment isolation valves.

Other air sub-components are in-scope, but are addressed in the systems that they are directly associated with:

- purge supply and exhaust boot seals (Containment Ventilation)
- main steam isolation valves (Main and Auxiliary Steam)
- auxiliary feedwater discharge and mini-recirc valves (Auxiliary Feedwater)

The SA sub-system consists of two air compressors, receivers, and the SA header piping and valves. The air compressors and aftercoolers are cooled by the SW System. In addition to supplying normal SA loads, SA is also a backup supply to IA, and a backup supply to the EBA sub-system. Normally one SA compressor is sufficient to supply system demands. The SA sub-system is normally in either continuous or intermittent operation during normal plant operation and shutdown. The in-scope portion of the SA sub-system includes the Containment isolation valves and boundary valves to the EBA sub-system.

The Emergency Breathing Air sub-system supplies emergency breathing air to the Control Room during some fire scenarios. It is considered a standby sub-system. The in-scope portion of the EBA sub-system consists of the air receivers, filters, and the associated piping and valves to support the system intended functions.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection, Station Blackout, and Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Plant Air System containing components subject to an AMR include those IA components that support the charging pump varidrives, pressurizer PORVs, the IA and SA Containment isolation valves, the SA boundary valves to the EBA sub-system, and EBA components from the air receivers to the connections in the Control Room.

Most systems interface with the Plant Air System, but the following systems have features to allow continued operation after a loss of IA:

Auxiliary Feedwater	Containment Ventilation
Main and Auxiliary Steam	Chemical and Volume Control
Class 1 Piping/Components	

System Function Listing

A comprehensive listing of functions associated with the Plant Air System, or specific components contained in the system, is provided in the summary below.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Instrument and Service Air sub-systems have Containment isolation valves that are isolated to prevent the release of radioactivity to the environment.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Instrument Air connections to nitrogen accumulators provide low temperature overpressure protection of the Reactor Coolant System via PORVs.

Instrument and Service Air provide oil-free compressed air for the operation of various components.

Service Air supplies a backup air supply to Instrument Air.

Emergency Breathing Air provides breathable air for refilling Scot Air Pack bottles.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The emergency breathing air (EBA) sub-system shall be capable of supplying breathing air to the control room.

The instrument air (IA) sub-system shall be capable of isolating instrument air to safe shutdown components and venting air to fail the components to their required safe shutdown positions. SOVs and I/Ps are addressed with their parent system/components.

The instrument air (IA) sub-system shall be capable of providing air to the charging pump controllers for speed control to support the reactor coolant make-up function, and to PORVs for RCS pressure control.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The instrument air (IA) sub-system contains electrical equipment that is environmentally qualified.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS STATION BLACKOUT (10 CFR 50.63)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The instrument air (IA) sub-system shall be capable of isolating instrument air to safe shutdown components and venting air to fail the components to their required safe shutdown positions. SOVs and I/Ps are addressed with their parent system/components.

FSAR Reference

Additional Plant Air System details are provided in Section 9.7 and Section 5.2 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Plant Air System are listed below:

Unit 1	Unit 2
LR-M-209, Sh. 2	LR-M-209, Sh. 2
LR-M-209, Sh. 7	LR-M-209, Sh. 7
LR-M-209, Sh 8	LR-M-209, Sh 8
LR-M-209, Sh. 11	LR-M-209, Sh. 11
LR-M-209, Sh. 13	LR-M-209, Sh. 13

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-15 along with each Component Group's intended function(s).

Table 2.3.3-15 Plant Air System

Component Group	Intended Function
ACCUMULATORS/CYLINDERS	PRESSURE BOUNDARY
COMPRESSOR CASING	PRESSURE BOUNDARY
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FILTERS/STRAINERS	PRESSURE BOUNDARY PROVIDE FILTRATION
FLOW INDICATORS	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
TANKS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.3.16 Containment Hydrogen Detectors and Recombiner System

System Description

The Containment Hydrogen Detectors and Recombiners System (generally referred to as the Post Accident Containment Vent (PACV)) provides a long-term method of controlling hydrogen accumulation within the Containment following a loss-of-coolant accident. The system includes independent sample, exhaust and supply piping connections, and the associated piping and valves to support the system intended functions. Each piping connection is equipped with redundant Containment isolation valves located to minimize personnel radiation exposure should valve operation be required. Exhaust piping discharges to either the Primary Auxiliary Building exhaust ventilation sub-system or a hydrogen recombiner (stored offsite). The Containment Hydrogen Detectors and Recombiner System contains Environmentally Qualified (EQ) components.

The Containment Hydrogen Detectors and Recombiner System is designed to maintain hydrogen concentration within the Containment following a loss-of-coolant accident below the lower flammable limit. If the hydrogen recombiner is utilized, the first step would be to have the recombiner shipped to PBNP. The recombiner would then be installed and started up within 6 1/2 days after the start of the accident. The Containment Hydrogen Detectors and Recombiner System is a standby system during normal plant operation.

The in-scope portion of the Containment Hydrogen Detectors and Recombiner System includes those safety related components that extend from the piping inside the Containment to the Containment isolation valves located outside Containment.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Containment Hydrogen Detectors and Recombiner System containing components subject to an AMR extend from the piping inside Containment to the Containment isolation valves, including associated piping and valves.

The following fluid systems interface with the Containment Hydrogen Detectors and Recombiner System:

None

System Function Listing

A comprehensive listing of functions associated with the Containment Hydrogen Detectors and Recombiner System, or specific components contained in the system, is provided in the summary below.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provides isolation of lines penetrating Containment to prevent the release of radioactivity to the environment.

Code L PROVIDE EMERGENCY HEAT REMOVAL FROM PRIMARY CONTAINMENT AND PROVIDE CONTAINMENT PRESSURE CONTROL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Provide a long-term method of controlling hydrogen accumulation, and thereby Containment pressure control within the Containment structure following a LOCA.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Provide radiation monitoring devices to support operator indication of plant conditions in accordance with the requirements of RG 1.97.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Containment Hydrogen Detectors and Recombiner System contains electrical equipment that is environmentally qualified.

FSAR Reference

Additional Containment Hydrogen Detectors and Recombiner System details are provided in Section 5.2, and Section 5.3.2.4 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Containment Hydrogen Detectors and Recombiner System are listed below:

Common
LR-M-224

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.3-16 along with each Component Group's intended function(s).

Table 2.3.3-16 Containment Hydrogen Detectors and Recombiner System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.4 Steam and Power Conversion System

The following systems are addressed in this section:

- Main and Auxiliary Steam System (Section 2.3.4.1)
- Feedwater and Condensate System (Section 2.3.4.2)
- Auxiliary Feedwater System (Section 2.3.4.3)

2.3.4.1 Main and Auxiliary Steam System

System Description

The Main and Auxiliary Steam System transports the steam produced in the steam generators to the main turbine for the production of electricity. The Main and Auxiliary Steam System provides heat removal from the Reactor Coolant System (RCS) during normal, accident and post accident conditions. The Main and Auxiliary Steam System also provides steam for the turbine-driven auxiliary feedwater pumps, which can be obtained from either main steam line, upstream of the main steam isolation valves. Some non-safety related portions of piping in the system have failure modes that could prevent the satisfactory accomplishment of safety related functions (due to high-energy line breaks) and are therefore in-scope in accordance with 10 CFR 54.4(a)(2) and the associated ISG (see Section 2.1.1.3.7). The Main and Auxiliary Steam System contains Environmentally Qualified (EQ) components and is also credited for use in safe shutdown following Station Blackout (SBO) events and some plant fires (Fire Protection). The Main and Auxiliary Steam System is in continuous operation during normal plant operation.

The principal components of the Main and Auxiliary Steam System are the main steam lines, auxiliary steam lines, and a steam generator blowdown sub-system. Each PBNP unit has two Steam Generators, and each Steam Generator has connections for each of the above principal components.

Each main steam line has four main steam safety valves and an atmospheric relief valve. The atmospheric relief valve has two functions. It offers overpressure protection to the steam generator at a set point below the main steam safety valve set points, and can be used to maintain RC temperature or perform a plant cooldown in the event the steam dump to the condenser is not available. Each main steam line is also equipped with a fast closing main steam isolation valve (MSIV) and a nonreturn check valve. The MSIV can isolate steam flow from its steam generator, and the non-return check valve prevents reverse flow in the main steam lines. The in-scope portion of the main steam line components extend from the steam generators to the seismic Class I boundary downstream of the nonreturn valves.

Auxiliary steam is supplied to the turbine-driven auxiliary feedwater pumps and radwaste steam sub-system. Each auxiliary steam line has a steam admission valve for both the turbine-driven auxiliary feedwater pump and radwaste steam sub-system. The in-scope portion of auxiliary steam lines are the piping components from the main steam lines to the auxiliary feedwater pump turbines (including exhaust from the turbine), and the radwaste steam lines until they exit the Primary Auxiliary Building (PAB).

The steam generator blowdown sub-system is used to reduce the quantities of solids that accumulate in the steam generators as a result of the boiling process. Blowdown piping runs from the steam generator to blowdown heat exchangers and tank located outside of containment. A Steam Generator Blowdown sample connection is also provided off of the blowdown piping. The portion of the steam generator blowdown sub-system that is in-scope includes the piping components that extend from the steam generators to the containment isolation valves outside containment.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Main and Auxiliary Steam System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Main and Auxiliary Steam System containing components subject to an AMR include main steam line components extending from the steam generators to downstream of the nonreturn valves, auxiliary steam lines to the turbine driven auxiliary feedwater pumps (including exhaust piping), radwaste steam lines until they exit the PAB, and steam generator blowdown and sample piping components that extend from the steam generators to the containment isolation valves.

The following fluid systems interface with the Main and Auxiliary Steam System:

Feedwater and Condensate	Plant Air
Auxiliary Feedwater	Steam Generators

System Function Listing

A comprehensive listing of functions associated with the Main and Auxiliary Steam System, or specific components contained in the system, is provided in the summary below.

Code D	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION	X						

Comment: Instrumentation within the Main and Auxiliary Steam System perform this primary design system function by detecting, initiating, and actuating automatic safety functions.

Code H	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
PROVIDE EMERGENCY HEAT REMOVAL FROM THE REACTOR COOLANT SYSTEM USING SECONDARY HEAT REMOVAL CAPABILITY	X						

Comment: Atmospheric steam dumps cooldown and depressurize the steam generators and the Main and Auxiliary Steam System provides steam to the turbine-driven AFP, to perform this primary design system function.

Code K	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
PROVIDE PRIMARY CONTAINMENT BOUNDARY	X						

Comment: The MSIVs and steam generators within the Main and Auxiliary Steam System perform this associated design system function to prevent the release of radioactivity to the environment.

Code T	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
NON-NUCLEAR SAFETY CLASS FUNCTIONS							

Comment: Provide turbine overspeed protection.

Dissipate reactor heat through condenser steam dumps.

Provide for secondary chemistry control.

Provide steam to the main turbines to produce power.

Code Y	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION		X					

Comment: This function identifies non-safety related components in the Main and Auxiliary Steam System whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Main and Auxiliary Steam System shall be capable of:

1. achieving and maintaining decay and sensible heat removal with at least one steam generator to support reactor heat removal.
2. providing steam to the turbine driven auxiliary feedwater pumps to support reactor heat removal.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Main and Auxiliary Steam System contains electrical equipment that is environmentally qualified.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The Main and Auxiliary Steam System shall be capable of:

1. achieving and maintaining decay and sensible heat removal with at least one steam generator to support reactor heat removal.
2. providing steam to the turbine driven auxiliary feedwater pumps to support reactor heat removal.

FSAR Reference

Additional Main and Auxiliary Steam System details are provided in Section 5.2, Section 7.2, Section 10.0, Section 10.1, and Section 10.2 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Main and Auxiliary Steam System are listed below:

Unit 1	Unit 2
LR-M-201, Sh. 1	LR-M-2201, Sh. 1
LR-M-201, Sh. 3	LR-M-2201, Sh. 3
LR-PBM-227	LR-PBM-227

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.4-1 along with each Component Group's intended function(s).

Table 2.3.4-1 Main and Auxiliary Steam System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
DRAIN TRAP	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW ELEMENTS	FLOW CONTROL PRESSURE CONTROL
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
RESTRICTING ORIFICES	PRESSURE BOUNDARY
STEAM TRAPS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.4.2 Feedwater and Condensate System

System Description

The Feedwater and Condensate System functions to condense the steam exhausted from the low-pressure turbines, collect this condensate, and then send it back to the steam generators for reuse. Components within the system are used to provide emergency heat removal from the Reactor Coolant System (RCS) using secondary heat removal capability. The Engineered Safety Features Actuation System (ESFAS) provides actuation signals for feedwater isolation. Portions of the Feedwater and Condensate System have failure modes that could prevent the satisfactory accomplishment of safety related functions (due to high-energy line breaks) and are therefore in-scope in accordance with 10 CFR 54.4(a)(2) and the associated ISG (see Section 2.1.1.3.7). The Feedwater and Condensate System contains Environmentally Qualified (EQ) components and is also credited for use in mitigating Anticipated Transients Without a Scram (ATWS), safe shutdown following Station Blackout (SBO) events, and some plant fires (Fire Protection). The Feedwater and Condensate System is normally in continuous operation during normal plant operation.

The principal components of the Feedwater and Condensate System are the feedwater and condensate pumps, feedwater regulating and bypass valves, feedwater heaters, and the associated piping and valves to support the system functions. The condensate pumps take suction from the condenser hotwell, and pump condensate forward through low pressure feedwater heaters, to the suction of the feedwater pumps. The feedwater pumps then pump feedwater through a high pressure feedwater heater, through the feedwater regulating and bypass valves, and to the steam generators. Each feedwater line is equipped with two check valves in series (one inside containment and one outside of containment), to prevent reverse flow of feedwater or auxiliary feedwater away from the steam generators.

The portion of the Feedwater and Condensate System that is in-scope extends basically from the feedwater regulating and bypass valves to the steam generators. Additionally, a small portion of non-safety condensate return piping from the steam generator blowdown heat exchangers is also in-scope, where it is in proximity to some vulnerable safety related equipment.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Feedwater and Condensate System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, Anticipated Transients Without a Scram, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Feedwater and Condensate System containing components subject to an AMR extend basically from the feedwater regulating valves to the steam generators.

The following fluid systems interface with the Feedwater and Condensate System:

Main and Auxiliary Steam	Plant Air
Auxiliary Feedwater	Steam Generators

System Function Listing

A comprehensive listing of functions associated with the Feedwater and Condensate System, or specific components contained in the system, is provided in the summary below.

Code D SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Instrumentation within the Feedwater and Condensate System perform this primary design system function by detecting, initiating, and actuating automatic safety functions.

Code H PROVIDE EMERGENCY HEAT REMOVAL FROM THE REACTOR COOLANT SYSTEM USING SECONDARY HEAT REMOVAL CAPABILITY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Feedwater to the steam generators within the Feedwater and Condensate System perform this primary design system function.

Feedwater isolation is required for the decay heat removal function to prevent excessive primary system cooldown in the event of an uncontrolled feedwater sub-system injection.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The feedwater check valves within the Feedwater and Condensate System perform this primary design system function to prevent the release of radioactivity to the environment.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Maintain steam generator level during normal operations.

Increase plant thermal efficiency.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety related components in the Feedwater and Condensate System whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Feedwater and Condensate System shall be capable of:

1. monitoring the process parameters for wide range steam generator level.
2. preventing injection into the steam generators from the main feed pumps to support reactor heat removal.

Portions of the Feedwater and Condensate System provide pressure boundary/flow paths to support auxiliary feedwater makeup to the SGs.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Feedwater and Condensate System contains electrical equipment that is environmentally qualified.

Code Z4 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ANTICIPATED TRANSIENTS WITHOUT SCRAM (10 CFR 50.62)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
						X	

Comment: The Feedwater and Condensate System shall provide input to the AMSAC (ATWS Mitigating System Actuation Circuit) to initiate auxiliary feedwater flow and turbine trip upon the loss of both steam generator feedwater pumps or closure of the feedwater regulator control valves.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: Portions of the Feedwater and Condensate System provide pressure boundary/flow paths to support auxiliary feedwater makeup to the SGs.

FSAR Reference

Additional Feedwater and Condensate System details are provided in Section 5.2, Section 7.2, Section 7.4, and Section 10.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Feedwater and Condensate System are listed below:

Unit 1	Unit 2
LR-M-201, Sh. 3	LR-M-2201, Sh. 3
LR-M-202, Sh. 1	LR-M-2202, Sh. 1
LR-M-202, Sh. 2	LR-M-2202, Sh. 2

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.4-2 along with each Component Group’s intended function(s).

Table 2.3.4-2 Feedwater and Condensate System

Component Group	Intended Function
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW ELEMENTS	FLOW CONTROL PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY

2.3.4.3 Auxiliary Feedwater System

System Description

The Auxiliary Feedwater System is designed to supply high-pressure feedwater to the steam generators in order to maintain a water inventory for removal of heat energy from the Reactor Coolant System (RCS) by secondary side steam release in the event of inoperability or unavailability of the main feedwater sub-system. One turbine-driven (per unit) and two electric-driven (shared by the two units) auxiliary feedwater (AF) pumps are provided to ensure that adequate feedwater is supplied to the steam generators for heat removal under all circumstances, including loss of power and loss of normal heat sink. AF flow can be maintained until power is restored or reactor decay heat removal can be accomplished by other systems. The Auxiliary Feedwater System contains Environmentally Qualified (EQ) components and is also credited for use in mitigating Anticipated Transients Without a Scram (ATWS), safe shutdown following Station Blackout (SBO) events, and some plant fires (Fire Protection).

The AF System consists of two electric motor-driven pumps, two steam turbine-driven pumps, condensate storage tanks, and the associated piping and valves to support the system functions. Redundancy is provided by utilizing two pumping systems, two different sources of power for the pumps, and two sources of water to supply the pumps. Nitrogen bottles and air accumulators are provided for Plant Air System backup to the AF pump discharge valves and mini-recirc valves. The normal water supply source for AF is by gravity feed from two Condensate Storage Tanks, while the backup safety related supply is provided by the Service Water System.

The Auxiliary Feedwater System is a standby system during normal plant operation. It is used during plant startup and shutdown and during hot shutdown or hot standby conditions when chemical additions or small feedwater flow requirements do not warrant the operation of the main Feedwater and Condensate System.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Auxiliary Feedwater System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, Anticipated Transients Without a Scram, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Auxiliary Feedwater System subject to an AMR extend from the Condensate Storage Tanks to the Steam Generators, including the associated pumps, piping, and valves, and portions of the air sub-system that are required to function after loss of normal plant air supply.

The following fluid systems interface with the Auxiliary Feedwater System:

Main and Auxiliary Steam	Fire Protection
Feedwater and Condensate	Plant Air
Service Water	

System Function Listing

A comprehensive listing of functions associated with the Auxiliary Feedwater System, or specific components contained in the system, is provided in the summary below.

Code H	Cri 1	Cri 2	Cri 3				
PROVIDE EMERGENCY HEAT REMOVAL FROM THE REACTOR COOLANT SYSTEM USING SECONDARY HEAT REMOVAL CAPABILITY			FP	EQ	PTS	AT	SB
	X						

Comment: Auxiliary Feedwater Pumps within the Auxiliary Feedwater System perform this primary design system function, by maintaining steam generator water level.

Code J PROVIDE HEAT REMOVAL FROM AND/OR PRESSURE BOUNDARY OF SAFETY RELATED HEAT EXCHANGERS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Auxiliary Feedwater System performs this associated design system function, by removing heat from the turbine bearing coolers.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Auxiliary Feedwater System provides containment isolation valves in lines penetrating the Containment to prevent the release of radioactivity to the environment.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Maintain steam generator level during startup and shutdown.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: This function identifies non-safety related components in the Auxiliary Feedwater System whose failure could affect safety related systems.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Auxiliary Feedwater System shall be capable of providing make-up water to the steam generators to support reactor heat removal.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Auxiliary Feedwater System contains electrical equipment that is environmentally qualified.

Code Z4	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ANTICIPATED TRANSIENTS WITHOUT SCRAM (10 CFR 50.62)			FP	EQ	PTS	AT	SB
						X	

Comment: The Auxiliary Feedwater System shall:

1. initiate all four AFW pumps upon receipt of an AMSAC signal.
2. provide input to the AMSAC (ATWS Mitigating System Actuation Circuit) to initiate auxiliary feedwater flow and turbine trip upon the loss of both steam generator feedwater pumps or closure of the feedwater regulator control valves.

Code Z5	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)			FP	EQ	PTS	AT	SB
							X

Comment: The Auxiliary Feedwater System shall be capable of providing make-up water to the steam generators to support reactor heat removal.

FSAR Reference

Additional Auxiliary Feedwater System details are provided in Section 5.2, Section 7.4, Section 10.0, Section 10.1, and Section 10.2 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Auxiliary Feedwater System are listed below:

Unit 1	Unit 2
LR-M-217, Sh. 1	LR-M-217, Sh. 1
LR-M-217, Sh. 2	LR-M-217, Sh. 2

Components Subject to an AMR

The component groups for this system that require aging management review are addressed in Table 2.3.4-3 along with each Component Group’s intended function(s).

Table 2.3.4-3 Auxiliary Feedwater System

Component Group	Intended Function
ACCUMULATORS/CYLINDERS	PRESSURE BOUNDARY
CS COMPONENTS	PRESSURE BOUNDARY
FASTENERS/BOLTING	MECHANICAL CLOSURE INTEGRITY
FLOW ELEMENTS	PRESSURE BOUNDARY
HEAT EXCHANGER	HEAT TRANSFER PRESSURE BOUNDARY
INSTRUMENT VALVE ASSEMBLIES	PRESSURE BOUNDARY
PIPING AND FITTINGS	PRESSURE BOUNDARY
PUMP CASING	PRESSURE BOUNDARY
RESTRICTING ORIFICES	PRESSURE BOUNDARY RESTRICTS FLOW
TANKS	PRESSURE BOUNDARY
TURBINE CASING	PRESSURE BOUNDARY
VALVE BODIES	PRESSURE BOUNDARY
VALVE OPERATOR	PRESSURE BOUNDARY

2.4 Scoping and Screening Results: Containments, Structures, and Component Supports

The following structural components are addressed in this section:

- Containment Unit 1/2 Building Structure (Section 2.4.1)
- Control Building Structure (Section 2.4.2)
- Circulating Water Pumphouse Structure (Section 2.4.3)
- Diesel Generator Building Structure (Section 2.4.4)
- Facade Unit 1/2 Structure (Section 2.4.5)
- Primary Auxiliary Building Structure (Section 2.4.6)
- Turbine Building Unit 1/2 Structure (Section 2.4.7)
- Yard Structures (Section 2.4.8)
- Cranes, Hoists, and Lifting Devices (Section 2.4.9)
- Component Supports Commodity Group (Section 2.4.10)
- Fire Barrier Commodity Group (Section 2.4.11)
- 13.8 KV Switchgear Building Structure (Section 2.4.12)
- Fuel Oil Pumphouse Structure (Section 2.4.13)
- Gas Turbine Building Structure (Section 2.4.14)

2.4.1 Containment Unit 1/2 Building Structure

Description

The Containment Unit 1/2 Building Structure consists of two prestressed, post tensioned, reinforced concrete right cylinders with flat base slabs and shallow domed roofs. Each Containment structure has a 1/4 in. thick welded steel liner attached to the inside face of the concrete shell to insure a high degree of leak tightness. The structures provide biological shielding for both normal and accident situations. The Unit 2 Containment is essentially identical in design and construction to that of Unit 1 except that it is oriented to conform to the overall site plan. Each Containment structure is entirely housed in an unheated enclosure (facade) that provides protection from the weather.

In each structure, the nominal 3 ft. 6 in. thick concrete cylindrical wall and 3 ft. thick dome are pre-stressed and post-tensioned. The nominal 9 ft. thick concrete base slab is reinforced with high strength reinforcing steel. The base liner is installed on top of the structural slab and is covered with concrete. The base slab is supported on H-piles driven to refusal (~65 to 75 ft.) in the underlying bedrock. Bearing plates are welded to the piles to transfer the pile reaction to the concrete without exceeding the allowable concrete stresses. The piles are embedded 3 feet into the mat. The H-piles are distributed under the mat with added concentration of piles under the outer circumference of the mat where the foundation loadings are greatest due to seismic or wind overturning forces.

The post-tensioning sub-system consists of: (1) 147 dome tendons anchored at the vertical face of the dome ring girder, (2) 168 vertical tendons anchored at the top surface of the ring girder and at the bottom of the base slab, and (3) 367 hoop tendons anchored at the six vertical buttresses. Each tendon consists of ninety 1/4 in. diameter wires with button headed BBRV type anchorages. The tendons are housed in spiral-wrapped corrugated thin wall sheathing and capped at each anchorage by a sheathing filler pressure-tight cap. The tendon sheathing and caps are filled with a corrosion preventive grease. The internal pressure loads on the base slab are resisted by both the piles and the strength of the reinforced concrete slab. Thus, post-tensioning is not required to exert an external pressure for this portion of the structure.

Reinforcing steel is used throughout the base slab, around the large penetrations, and at areas of discontinuities. Also it is used throughout the cylinder and dome as crack control reinforcing.

The 1/4 in. thick liner plate is attached to the concrete by means of an angle grid system stitch welded to the liner plate and embedded in the concrete. The frequent anchoring is designed to prevent significant distortion of the liner plate during accident conditions and to insure that the liner maintains its leak tight integrity. The liner plate is fabricated with a leak chase channel (LCC) system which covers all welded seams in the liner plate. They are considered an integral part of the liner plate and therefore a part of the leak tight containment pressure boundary.

The reinforced concrete and steel framed internal structure consists of several levels/compartments supported on the basemat by concrete or steel columns. The internal structure is isolated from the containment shell by a seismic gap which also permits the distribution and dissipation of any internal differential pressure during postulated accident events. The various floors are at 8'-0", 21'-0", 46'-0", and 66'-0", and the refueling cavity is included. During refueling, the refueling cavity to reactor vessel interface is sealed with a reactor cavity seal ring. There are several compartments which house mechanical equipment. They are the steam generator and reactor coolant pump compartments, pressurizer compartment, and the reactor cavity. Structural brackets are provided for the containment crane runway and for the dome liner erection trusses, fabricated of structural steel. The structural brackets and reinforcing plates were shop fabricated and then shipped to the job site for welding into the 1/4 in. liner plate similar to the penetration assemblies.

Numerous mechanical and electrical systems penetrate the containment wall through welded steel penetrations. All piping and ventilation penetrations are of the rigid welded type and are solidly anchored to the containment wall, thus eliminating the need to use expansion bellows for containment barriers inside containment. Butt welds are used between the penetration sleeve and process piping. Both flued ends and drilled standard weight pipe caps are used for the closure piece between the sleeves and the pipes. Each double barrier penetration assembly and its connection to the piping are designed to withstand the maximum pressure in the annulus between the pipe and the penetration assembly resulting from the rupture of any one process line. Any potential leak path in piping and ventilation penetrations also has provisions for individual testing.

Electrical penetrations consist of carbon steel pipe canisters with stainless steel header plates welded to each end. Identical hermetically ceramic sealed multipin connectors are welded into both headers for all conductors rated less than 600 volts. High voltage conductors utilize single conductor hermetically sealed ceramic bushings welded to both header plates. Thus, each canister affords a double barrier against leakage. A flange on each canister is welded to the penetration sleeve. The canister with two welded headers permits pressure and leakage tests to be performed. A tap, convenient to the exterior of the containment, is provided for pressurizing the canister.

Large equipment access is via a 15 ft. clear diameter double gasketed equipment hatch, with an integral double door emergency personnel airlock. The dished equipment hatch is fabricated from steel and furnished with a double gasketed flange. Provision is made to allow test pressurization of the spaces between the double gaskets of the hatch and its flange and the weld seam channels at the liner joint, hatch flanges, and dished hatch.

Two personnel airlocks are provided (one of which is associated with the equipment hatch as noted above). Each personnel airlock is a double door, welded steel assembly. The locks are designed to withstand all containment design conditions with either or both doors closed and locked. Doors open toward the center of the containment and are thus sealed under containment pressure. The lock barrel may be pressurized to demonstrate its leak tightness without pressurizing the containment. Quick acting type equalizing valves connect the personnel lock with the interior and exterior of the containment vessel for the purposes of equalizing pressure in the two systems when entering or leaving the containment. Each air lock door is provided with double gaskets to permit pressurization between the gaskets for leakage testing.

A fuel transfer penetration is provided in each containment structure for fuel movement between the refueling transfer canal and the spent fuel pool. The penetration consists of a 20 in. stainless steel pipe installed inside a 24 in. pipe. The inner pipe acts as the transfer tube and is fitted with a double gasketed blind flange in the refueling cavity and a standard gate valve in the spent fuel pool canal. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment liner and provision is made by use of continuous leakchase channels for test pressurizing all welds essential to the integrity of the penetration during plant operation. Bellows expansion joints are provided on the pipes to compensate for any differential movement between the two pipes or other structures.

The containments interface with other commodity group or building evaluations. These building/commodity interfaces include the:

- Component Supports; for the pipe restraints and equipment supports (including the RCS Class 1 equipment supports)
- Fire Barrier; for the fire stops and fire wraps within the containments
- Cranes, Hoists, and Lifting Devices; for the containment cranes and their lifting devices
- Facade Unit 1/2 Structure; for the lateral and roof support provided by the containment

The description above results in some SSCs in the buildings being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Containment Unit 1/2 Building Structure are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Containment Unit 1/2 Building Structure containing components subject to an AMR include the walls, dome, foundations, tendons, internal structures, floors, ceilings, beams, and columns. Major components include the liner plate, penetrations, airlocks and equipment hatches.

System Function Listing

A comprehensive listing of functions associated with the Containment Unit 1/2 Building Structure, or specific components contained in the structure, is provided in the summary below.

Code K PROVIDE PRIMARY CONTAINMENT BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The reactor Containment structures completely encloses the entire reactor and reactor coolant system and ensures that an acceptable upper limit for leakage of radioactive materials to the environment is not exceeded even if gross failure of the reactor coolant system occurs.

Code R STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Containment Structure houses a substantial amount of safety related mechanical and electrical equipment and components such as the reactor vessels, steam generators, reactor coolant pumps, the pressurizer, and the containment cooler.

Code Y CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: The internal structure to the Containment Structure houses and supports the refueling cavity, which utilizes the reactor cavity seal ring during refueling.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: Structures shall maintain there fire rating to prevent spread of fire beyond defined Fire Area boundaries.

FSAR Reference

Additional Containment Unit 1/2 Building Structure details are provided in Section 2.5, Section 2.8, Section 5.1, Section 5.1.1.1, Section 5.1.2.6, and Section 9.4 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Containment Unit 1/2 Building Structure are listed below:

<u>Common</u>
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Containment Unit 1/2 Building Structure that require aging management review are addressed in Table 2.4.1-1 along with each component group’s intended function(s).

Table 2.4.1-1 Containment Unit 1/2 Building Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - BASEMAT	DIRECT FLOW PRESSURE BOUNDARY SHELTER SR SUPPORT NSR SUPPORT SR
CONCRETE/INDOOR - ALL: CYLINDER WALLS AND BUTTRESSES; DOME AND RING GIRDER	DIRECT FLOW FIRE BARRIER FLOOD BARRIER HEAT SINK MISSILE BARRIER PIPE WHIP RESTRAINT PRESSURE BOUNDARY RADIATION SHIELDING SHELTER SR SUPPORT NSR SUPPORT SR

Table 2.4.1-1 Containment Unit 1/2 Building Structure

Component Group	Intended Function
CONCRETE/INDOOR - ALL: INTERNAL STRUCTURE - COLUMNS, BEAMS, SLABS, AND WALLS	DIRECT FLOW FIRE BARRIER FLOOD BARRIER HEAT SINK MISSILE BARRIER PIPE WHIP RESTRAINT RADIATION SHIELDING SHELTER SR SUPPORT NSR SUPPORT SR
ELASTOMER/BORATED WATER - ALL: RV CAVITY SEAL RING	PRESSURE BOUNDARY
ELASTOMER/INDOOR - ALL: AIRLOCK DOOR SEALS, PENETRATIONS - ELECTRICAL	PRESSURE BOUNDARY
GROUT/INDOOR - ALL: COLUMN BASEPLATES; MISCELLANEOUS STEEL STRUCTURES	SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: DOME TRUSS; MISCELLANEOUS STEEL STRUCTURES; CAST-IN PLACE ANCHOR BOLTS	SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL/INDOOR - ALL: AIRLOCKS AND EQUIPMENT HATCHES INCLUDING BOLTING	FIRE BARRIER PRESSURE BOUNDARY

Table 2.4.1-1 Containment Unit 1/2 Building Structure

Component Group	Intended Function
STRUCTURAL CARBON STEEL/INDOOR - ALL: CONTAINMENT LINER & KEYWAY CHANNELS	DIRECT FLOW HEAT SINK PIPE WHIP RESTRAINT PRESSURE BOUNDARY SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL/INDOOR - ALL: EXPOSED PORTIONS OF EMBEDDED STEEL; FRAMING - COLUMNS, BEAMS, BRACING, BASEPLATES, DOME TRUSS, AND CRANE SUPPORTS; PLATFORMS, GRATING, STAIRS, LADDERS, AND CHECKERED PLATES; CRDM MISSILE SHIELD	DIRECT FLOW HEAT SINK MISSILE BARRIER PIPE WHIP RESTRAINT SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL/INDOOR - ALL: PENETRATIONS - ELECTRICAL	FIRE BARRIER PRESSURE BOUNDARY
STRUCTURAL CARBON STEEL/INDOOR - ALL: PENETRATIONS - MECHANICAL, INCLUDING BOLTING	FIRE BARRIER PRESSURE BOUNDARY
STRUCTURAL CARBON STEEL/INDOOR - ALL: POST-TENSIONING TENDONS	PRESSURE BOUNDARY SHELTER SR SUPPORT SR
STRUCTURAL COPPER ALLOY/INDOOR - ALL: AIRLOCK BUSHINGS	FIRE BARRIER PRESSURE BOUNDARY

Table 2.4.1-1 Containment Unit 1/2 Building Structure

Component Group	Intended Function
STRUCTURAL STAINLESS STEEL FASTENERS/INDOOR - ALL: MISCELLANEOUS ITEMS	SUPPORT NSR SUPPORT SR
STRUCTURAL STAINLESS STEEL/BORATED WATER -ALL: REFUELING CAVITY LINER; SANDBOX COVERS INCLUDING BOLTING; PLATES, BARS, STRIPS, AND RODS ASSOCIATED WITH THE RC; FUEL TRANSFER TUBE INCLUDING BOLTING	FIRE BARRIER HEAT SINK PRESSURE BOUNDARY RADIATION SHIELDING
STRUCTURAL STAINLESS STEEL/INDOOR - ALL: PENETRATIONS - ELECTRICAL	FIRE BARRIER PRESSURE BOUNDARY
STRUCTURAL STAINLESS STEEL/INDOOR - ALL: MISCELLANEOUS ITEMS, REACTOR CAVITY LINER	DIRECT FLOW HEAT SINK SUPPORT SR
STRUCTURAL STEEL PILES/ BURIED - ALL: CARBON STEEL H-PILES - FOUNDATION	SUPPORT SR

2.4.2 Control Building Structure

Description

The Control Building (CB) is a rectangular, safety related, seismic Class I structure that is constructed from reinforced concrete with internal bracing provided by reinforced concrete walls, columns, and floors. The CB is adjacent to the Primary Auxiliary Building and enveloped by the Unit 1 and Unit 2 Turbine Buildings. The CB is enclosed within the Turbine Buildings, but is an independent structure since it has no fixed structural attachments with either the Turbine Buildings or the Primary Auxiliary Building. The CB contains the Control Room, Computer Room, Control Room Ventilation Room, Cable Spreading Room, Vital and Non-Vital Switchgear Rooms, Battery Rooms, Auxiliary Feed Water Pumps, Train 'A' Emergency Diesel Generators, and air compressors. The CB also provides support for the Condensate Storage Tanks and operations offices.

The CB's structure consists of several areas on four levels, which are separated by reinforced concrete walls and floors or concrete masonry block walls. The building's basemat, elevation 8'-0", and foundation footings consist of reinforced concrete supported on compacted subgrade. The building's intermediate reinforced concrete floors are at elevations 26'-0", 44'-0", and 60'-0". The building's highest level, the reinforced concrete roof for elevation 60'-0", is at elevation 74'-0".

The description above results in some SSCs in this structure being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Control Building Structure are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Control Building Structure containing components subject to an AMR include the walls, roof, foundations, floors, doors, ceilings, beams, and columns.

System Function Listing

A comprehensive listing of functions associated with the Control Building Structure, or specific components contained in the structure, is provided in the summary below.

Code R	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS	X						

Comment: The safety related, seismic Class I CB provides structural support and housing to safety related SSCs. These SSCs include items such as the Cable Spreading Room and its associated panels/cabinets/racks, Control Room and Computer Room panels/control boards/racks/cabinets, emergency diesel generator and their associated equipment, Vital Switchgear Room and its associated vital switchgear, 480 VAC load centers, 125 VDC electrical power, SW piping, and AFW Pumps.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The safety related, seismic Class I CB provides support and housing to non-safety related equipment, whose failure would not adversely affect safety related equipment or equipment functions. This equipment includes the non-vital 4160 VAC switchgear, service and instrument air compressors, 125 VDC battery/electrical panels/distribution, and turbine instrument control panels. The CB facilitates access control to individual rooms within the CB.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: The safety related, seismic Class I CB provides support to non-safety related SSCs, whose failure could adversely affect safety related functions. These CB SSCs include items such as the flood barriers (e.g., wall separating CSTs from the Non-Vital Switchgear Area, Subsoil Drain sub-system covers, doors), HELB barriers (e.g., the Non-Vital Switchgear Area south HELB shield wall, the Cable Spreading Room HELB shield walls, doors), and Control Room habitability (accident radiation shielding and atmosphere control envelope).

Code Z1 LICENSE RENEWAL CRITERION 3 (FP/APP R) - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The safety related, seismic Class I CB contains SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site's implementation of Fire Protection regulations. The CB includes structures such as concrete and masonry concrete block walls and fire rated doors.

Code Z5 LICENSE RENEWAL CRITERION 3 (SBO) - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATION TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR STATION BLACKOUT (10 CFR 50.63)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The safety related, seismic Class I CB contains SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site's coping with a Station Blackout. The CB's Control Room and Computer Room reinforced concrete walls, floors and ceilings are credited as heat sinks.

FSAR Reference

Additional Control Building Structure details are provided in Section 2.5, Section 2.6, Section 2.8, and Section A.2.3 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Control Building Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Control Building Structure that require aging management review are addressed in Table 2.4.1-1 along with each component group's intended function(s).

Table 2.4.2-1 Control Building Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - SPREAD FOOTINGS	SHELTER SR SUPPORT NSR SUPPORT SR

Table 2.4.2-1 Control Building Structure

Component Group	Intended Function
CONCRETE/INDOOR - ALL: WALLS, CEILINGS, FLOORS, COLUMNS; EQUIPMENT PEDESTALS; SPRAY WALLS (AFWP RM)	FIRE BARRIER FLOOD BARRIER HEAT SINK HELB SHIELDING MISSILE BARRIER RADIATION SHIELDING SHELTER SR SUPPORT NSR SUPPORT SR
CONCRETE/OUTDOOR - ALL: WALL - EAST	FIRE BARRIER FLOOD BARRIER MISSILE BARRIER SHELTER SR SUPPORT SR
DOORS/INDOOR - ALL: ALL DOORS THROUGHOUT THE BUILDING	FIRE BARRIER FLOOD BARRIER HELB SHIELDING
ELASTOMERS/INDOOR - ALL: RUBBER FLAP - DGR LOUVER; RUBBER SILL, SWEEP - FLOOD DOORS; GASKET AND SEALS - CONTROL ROOM DOORS	FLOOD BARRIER

Table 2.4.2-1 Control Building Structure

Component Group	Intended Function
GLASS/INDOOR - ALL: GLASS WINDOWS - CONTROL ROOM WALL (NORTH, SOUTH, AND EAST); GLASS WINDOWS - COMPUTER RM (EAST WALL)	HELB SHIELDING SHELTER SR
GROUT/INDOOR - ALL: MISCELLANEOUS STEEL STRUCTURES	SUPPORT NSR SUPPORT SR
MASONRY BLOCK WALL/OUTDOOR - ALL: DIESEL GENERATOR ROOM (DGR) - EAST WALL	FLOOD BARRIER
MASONRY BLOCK WALLS/INDOOR - ALL: BATTERY ROOM, NON-VITAL SWITCHGEAR ROOM (NON-VSR), CONTROL ROOM - INTERNAL (CR), DGR AND AFW PUMP (AFWP) RM TUNNEL	FIRE BARRIER FLOOD BARRIER SHELTER SR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: SUBSOIL DRAIN COVER; WALL PANELS AND PLATES, BRACING; HELB AND FLOOD BARRIERS; DOOR BRACES; PLATFORMS, STAIRS	SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL FASTENERS/OUTDOOR - ALL: MISSILE SHIELD - DGR; CORNER PLATES - DGR (EAST WALL)	SUPPORT NSR SUPPORT SR

Table 2.4.2-1 Control Building Structure

Component Group	Intended Function
STRUCTURAL CARBON STEEL/INDOOR - ALL: HELB BARRIERS - CABLE SPREADING RM (CSR) NORTH AND SOUTH WALL, NON-VSR - SOUTH WALL AND BRACES, AND EAST WALL BARRIERS AROUND CABLE TRAYS; SW GUARD PIPE - BATTERY RM; CST SUPPLY GUARD PIPE - 1E BATTERY RM (26 EL); DOOR BRACES - VSR SOUTH AND WEST WALLS; WALL PLATES - CSR NORTH AND SOUTH WALLS; WALL PANELS - CR NORTH, SOUTH AND EAST WALLS; FLOOD BARRIER - NON-VSR (EAST WALL); MASONRY WALL BRACING; PLATFORMS, STAIRS	FLOOD BARRIER HELB SHIELDING SHELTER SR SUPPORT SR
STRUCTURAL CARBON STEEL/OUTDOOR - ALL: MISSILE BARRIER AND BRACING - DGR AIR INTAKE	MISSILE BARRIER SUPPORT SR
STRUCTURAL CAST IRON/INDOOR - ALL: FLOOR DRAIN COVERS AND FLANGES (DGR, VITAL SWITCHGEAR ROOM (VSR), AFWP RM)	FLOOD BARRIER
WOOD/OUTDOOR - ALL: MISSILE SHIELD - INTEGRAL PART OF DIESEL GENERATOR AIR INTAKE	MISSILE BARRIER

2.4.3 Circulating Water Pumphouse Structure

Description

The Circulating Water Pumphouse (CWPH) structure consists of four interconnected facilities, the forebay, the CWPH building, the intake crib, and the discharge flumes. Only the forebay and CWPH building are in the scope of license renewal. In an emergency there are four separate flow paths into the forebay (two intake pipes and two discharge flumes), only one of which is needed. The intake crib (non-safety related) is completely submerged offshore. It connects with the forebay's surge chambers via two 14' diameter pipes that are buried below the lakebed. The forebay channels the lake water to the pump bay within the CWPH building. The CWPH building contains pumps for the Circulating Water System, Service Water System, and Fire Protection System. Two discharge flumes (non-safety related) are attached to the east wall of the forebay's seal wells and extend into Lake Michigan. Circulating water discharge from the Units 1 and 2 condensers empties into their separate seal wells via two 12' diameter pipes and then flows to the discharge flumes via 14' diameter valves.

The forebay is a reinforced concrete structure (walls, floor) set back 65 feet from the shoreline. The forebay is exposed to outdoor weather above and has vertical walls parallel and perpendicular to the shoreline that define its boundary. The forebay and CWPH are supported on a spread mat foundation upon glacial overburden above bedrock. This foundation forms the common floor of the forebay and CWPH building at elevation (-)28'-6". The CWPH building is a seismic Class I reinforced concrete structure with its operating floor at elevation 7'-0". The superstructure is constructed of reinforced concrete walls around the periphery. Interior walls, which partially segregate the Service Water System and Fire Protection System pumps from the Circulating Water System pumps, consist of reinforced concrete. The roof is a concrete slab supported on structural steel framing. The structural steel frame is supported on concrete pilasters in the perimeter walls and steel columns in the center of the building.

The description above results in some SSCs in this structure being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Circulating Water Pumphouse Structure containing components subject to an AMR include the walls, roof, foundations, floors, doors, ceilings, beams, and columns.

System Function Listing

A comprehensive listing of functions associated with the Circulating Water Pumphouse Structure, or specific components contained in the structure, is provided in the summary below.

Code R STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The Circulating Water Pumphouse structurally supports and houses six service water pumps.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Circulating Water Pumphouse structurally supports and houses two screen wash pumps, four circulating water pumps, and eight traveling water screen units.

Code Z1 LICENSE RENEWAL CRITERION 3 (FP/APP R)-CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Circulating Water Pumphouse structurally supports and houses two fire water pumps including a jockey pump.

A six-foot high one-hour fire rated wall is provided as an exemption for the Appendix R 20' separation requirement for fire protection. This wall separates the service water pumps into two groups of three.

FSAR Reference

Additional Circulating Water Pumphouse Structure details are provided in Section 1.3, Section 2.5, Section 2.6, and Section 2.8 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Circulating Water Pumphouse Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Circulating Water Pumphouse Structure that require aging management review are addressed in Table 2.4.3-1 along with each component group's intended function(s).

Table 2.4.3-1 Circulating Water Pumphouse Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - BASEMAT	SHELTER SR SUPPORT SR
CONCRETE/INDOOR - ALL: FLOORS; MISSILE BARRIER; NON-COMBUSTIBLE WALL (SW PUMPS)	FIRE BARRIER FLOOD BARRIER MISSILE BARRIER SHELTER SR SUPPORT SR
CONCRETE/OUTDOOR - ALL: WALLS, ROOF	FIRE BARRIER FLOOD BARRIER MISSILE BARRIER SHELTER SR SUPPORT SR
CONCRETE/RAW WATER - ALL: FOREBAY STRUCTURE AND PUMP BAYS	FLOOD BARRIER SHELTER SR SUPPORT SR WATER SOURCE
DOORS/INDOOR - ALL: ALL DOORS THROUGHOUT THE BUILDING	FIRE BARRIER

Table 2.4.3-1 Circulating Water Pumphouse Structure

Component Group	Intended Function
GROUT/INDOOR - ALL: COLUMN BASEPLATES	SUPPORT SR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: STRUCTURAL STEEL FRAMING	SUPPORT SR
STRUCTURAL CARBON STEEL/INDOOR - ALL: FRAMING - COLUMNS, BEAMS	MISSILE BARRIER SHELTER SR SUPPORT SR

2.4.4 Diesel Generator Building Structure

Description

The Diesel Generator Building (DGB) is a rectangular, safety related, seismic Class I structure with an attached non-safety related, seismic Class 3 stairway-passageway enclosure along the building's west side. The building is an independent structure with no other buildings in its immediate vicinity. The safety related, seismic Class I portion of the DGB is constructed from reinforced concrete with internal bracing provided by reinforced concrete walls and floors. The DGB houses the Train 'B' Emergency Diesel Generators, including their support equipment and distribution switchgear, and the Fuel Oil Storage Tanks, and fuel oil transfer pumps that service all four Emergency Diesel Generators.

The seismic Class I part of the DGB consists of multiple compartments on two levels, elevations 28'-0" and 50'-0". The building's basemat, elevation 28'-0", and foundation footings consist of reinforced concrete supported on compacted subgrade. The building's highest level, the reinforced concrete roof for elevation 50'-0", is at elevation 66'-0" (nominal). The building's non-safety related seismic Class 3 stairway-passageway enclosure is constructed from structural steel and metal siding.

The description above results in some SSCs in this structure being considered in-scope (Class 3 stairway excluded) in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Diesel Generator Building Structure are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Station Blackout and Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Diesel Generator Building Structure containing components subject to an AMR include the walls, roof, foundations, floors, doors, ceilings, beams, and columns.

System Function Listing

A comprehensive listing of functions associated with the Diesel Generator Building Structure, or specific components contained in the structure, is provided in the summary below.

Code R STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: The safety related, Seismic Class I DGB provides structural support and housing to safety related SSCs. These DGB SSCs include items such as emergency diesel generators and their associated support equipment, and emergency diesel generator fuel oil storage tanks and their associated transfer pumps.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The safety related, Seismic Class I DGB provides support and housing to non-safety related equipment, whose failure would not adversely affect safety related equipment or equipment functions The DGB accommodates access control attributes and appearance (cosmetic/aesthetic) consistent with other site buildings.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: The safety related, Seismic Class I DGB provides support to non-safety related SSCs, whose failure could adversely affect safety related functions. These DGB SSCs include items such as the room and monorail cranes, missile barriers, and other miscellaneous mechanical and electrical equipment.

Code Z1 LICENSE RENEWAL CRITERION 3 (FP/APP R) - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The safety related, Seismic Class I DGB contains SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site's implementation of Fire Protection regulations. The DGB includes structures such as walls consisting of greater than 10" of concrete and fire rated doors.

Code Z5 LICENSE RENEWAL CRITERION 3 (SBO) - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The DGB contains SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site's implementation of the Station Blackout regulation. The PBNP SBO position permits use of either the GTG or an EDG as the AAC source.

FSAR Reference

Additional Diesel Generator Building Structure details are provided in Section 2.5, Section 2.6, and Section 2.8 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Diesel Generator Building Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Diesel Generator Building Structure that require aging management review are addressed in Table 2.4.4-1 along with each component group's intended function(s).

Table 2.4.4-1 Diesel Generator Building Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - FOOTINGS AND BASEMAT	SHELTER SR SUPPORT NSR SUPPORT SR
CONCRETE/INDOOR - ALL: WALLS, FLOORS AND CEILINGS	FIRE BARRIER MISSILE BARRIER SHELTER SR SUPPORT NSR SUPPORT SR
CONCRETE/OUTDOOR - ALL: WALLS, ROOF	FIRE BARRIER MISSILE BARRIER SHELTER SR SUPPORT NSR SUPPORT SR
DOORS/OUTDOOR - ALL: ALL DOORS THROUGHOUT THE BUILDING	FIRE BARRIER SUPPORT NSR
DOORS/INDOOR - ALL: ALL DOORS THROUGHOUT THE BUILDING	FIRE BARRIER
GROUT/INDOOR - ALL: PLATFORMS, STAIRS	SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: PLATFORMS, STAIRS; MISSILE SHIELDS	SUPPORT NSR

Table 2.4.4-1 Diesel Generator Building Structure

Component Group	Intended Function
STRUCTURAL CARBON STEEL FASTENERS/OUTDOOR - ALL: MISSILE SHIELDS	SUPPORT NSR
STRUCTURAL CARBON STEEL/INDOOR - ALL: FRAMING - CRANE RAILS SUPPORTS; PLATFORMS, STAIRS	SUPPORT NSR
STRUCTURAL CARBON STEEL/OUTDOOR - ALL: MISSILE SHIELDS; WALL PLATES AT MISSILE SHIELDS	MISSILE BARRIER SUPPORT NSR

2.4.5 Facade Unit 1/2 Structure

Description

The Unit 1 and Unit 2 Facade Structures are seismic Class 3 structures consisting primarily of steel framing and metal siding. The Facade’s perimeter wall framing is supported vertically on reinforced concrete walls that are supported on an independent reinforced concrete foundation. The Facade structures have no intermediate floors other than a stair tower that provides access to upper elevations of the Primary Auxiliary Building and Containment. The Facades surround and enclose the reinforced concrete Containment structures and function primarily to provide the Containments with a sheltered environment.

The top of the Facade Structures' foundation are at elevation 6'-6". A reinforced concrete wall around the perimeter extends to elevation 31'-0". Structural steel framing with metal siding extend from the concrete walls to the roof, elevation 160'-0" (nominal). The Facades' framing relies on lateral support from the Primary Auxiliary Building steel superstructure and the Containment building. Additionally, the Facades' roof is partially supported by the Containments' concrete dome through steel base plates secured to the domes with anchor bolts and structural steel.

Since some SSCs in the Facade Unit 1/2 Structure are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2).

The portions of the Facade Unit 1/2 Structure containing components subject to an AMR include the walls, roof truss, foundations, beams, and columns.

System Function Listing

A comprehensive listing of functions associated with the Facade Unit 1/2 Structure, or specific components contained in the structure, is provided in the summary below.

Code T NON-NUCLEAR CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Facade Structures houses non-safety related equipment such as the reactor makeup water tanks, main steam and feed water piping.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: The facade structures are attached to and enclose the containment structures. The structures provide no physical protection from design basis external hazards. They provide weather protection for equipment and personnel and improve the architectural treatment of the plant.

FSAR Reference

Additional Facade Unit 1/2 Structure details are provided in Section 2.0, Figure 2.6-1, and Appendix A.5 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Facade Unit 1/2 Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Facade Unit 1/2 Structure that require aging management review are addressed in Table 2.4.5-1 along with each component group's intended function(s).

Table 2.4.5-1 Facade Unit 1/2 Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - SPREAD FOOTINGS	SUPPORT NSR
CONCRETE/INDOOR - ALL: FLOOR	SUPPORT NSR
CONCRETE/OUTDOOR - ALL: RETAINING WALLS	SUPPORT NSR
GROUT/INDOOR - ALL: COLUMN BASEPLATES	SUPPORT NSR
MASONRY BOCK WALL/INDOOR - ALL: ELEVATORS AND STAIRS TOWERS	SUPPORT NSR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: STRUCTURAL STEEL FRAMING; STEEL FRAMING FOR ELEVATOR AND STAIR TOWERS	SUPPORT NSR
STRUCTURAL CARBON STEEL/INDOOR - ALL: FRAMING - COLUMNS, BEAMS; ROOF TRUSS	SUPPORT NSR

2.4.6 **Primary Auxiliary Building Structure**

Description

The Primary Auxiliary Building (PAB) is a rectangular, multi-floored, reinforced concrete and steel framed structure consisting of a central area, and north and south wings. The PAB internal bracing is provided by reinforced concrete walls, floors, and slabs, and structural steel framing. The reinforced concrete PAB central area, and portions of the reinforced concrete north and south wings are seismic Class I structures. The PAB's steel superstructure is seismic Class 3. Each PAB area is founded on its own basemat.

Additionally, the Spent Fuel Pool, a seismic Class I structure located within the central area of the PAB, is founded on its own basemat supported by steel H-piles driven to bedrock. The PAB's exterior is clad with metal wall panels. Four reinforced concrete pipeways extend from the PAB through the Facades to the Containments.

The PAB north wing structure, column lines 13 to 15 at elevations 8'-0" and 26'-0", is seismic Class I. Also included in the review of the PAB is a portion of the South Service Building (SSB), a Class III structure. The SSB that extends from column line 5 to the north is within scope of LR. The PAB south wing structure, column lines 5 to 10 at elevation 8'-0" and column lines 8 to 10 at elevation 26'-0", is seismic Class I. The PAB structure has basement floors at elevations (-)19'-3" and (-)5'-3", a ground floor at elevation 8'-0", an intermediate floor at elevation 26'-0", and operating floors at elevations 46'-0", 52'-0", and 66'-0". The roof is at elevation 111'-9" (nominally). The Boiler Room and Water Treating areas located in the PAB north wing have a roof at elevation 52'-0".

The description above results in some SSCs in this structure being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Primary Auxiliary Building Structure are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Primary Auxiliary Building Structure containing components subject to an AMR include the new and spent fuel storage racks, walls, roof, foundations, floors, doors, ceilings, beams, and columns.

System Function Listing

A comprehensive listing of functions associated with the Primary Auxiliary Building Structure, or specific components contained in the structure, is provided in the summary below. Note: The structural component function(s) may support the intended function(s) of the structure or may have a unique function that does not support the intended function of the structure. A case in point is the spent fuel storage racks that are located in the Primary Auxiliary Building Structure. A unique function of the boraflex in the spent fuel storage racks is to maintain subcriticality of the fuel assemblies, which is not considered to be an intended function of the Primary Auxiliary Building Structure itself.

Code R	Cri 1	Cri 2	Cri 3				
STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS			FP	EQ	PTS	AT	SB
	X						

Comment: The Primary Auxiliary Building structurally supports and houses safety related equipment such as the charging pumps, component cooling water pumps and heat exchangers, residual heat removal pumps and heat exchangers, safety injection pumps, and the spent fuel pool. The South Service Building and Boiler Room and Water Treatment Areas support and house the feed flow transmitters.

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: The Primary Auxiliary Building structurally supports and houses non-safety related equipment such as the boric acid transfer pumps, monitor tank pumps, boric acid tanks, gas decay tanks, and volume control tanks.

Code Y	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION			FP	EQ	PTS	AT	SB
		X					

Comment: The Primary Auxiliary Building structurally supports and houses non-safety related equipment which can affect safety related equipment such as the Primary Auxiliary Building crane, HELB and flood doors, and spray shields.

Code Z1	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 (FP/APP R)- CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)			FP	EQ	PTS	AT	SB
			X				

Comment: Masonry block walls and fire doors within the Primary Auxiliary Building are relied upon for fire protection.

FSAR Reference

Additional Primary Auxiliary Building Structure details are provided in Section 1.3, Section 2.5, Section 2.6, Section 2.8, Section 9.4, and Appendix A.2.6 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Primary Auxiliary Building Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Primary Auxiliary Building Structure that require aging management review are addressed in Table 2.4.6-1 along with each component group's intended function(s).

Table 2.4.6-1 Primary Auxiliary Building Structure

Component Group	Intended Function
BORAFLEX/BORATED WATER - ALL: SPENT FUEL STORAGE RACKS	MAINTAIN SUBCRITICALITY
CONCRETE/BURIED - ALL: FOUNDATION - BASEMAT	SHELTER SR SUPPORT NSR SUPPORT SR
CONCRETE/INDOOR - ALL: WALLS, CEILINGS, FLOORS; SPENT FUEL POOL	FIRE BARRIER FLOOD BARRIER MISSILE BARRIER SHELTER SR SUPPORT NSR SUPPORT SR

Table 2.4.6-1 Primary Auxiliary Building Structure

Component Group	Intended Function
CONCRETE/OUTDOOR - ALL: WALLS	FIRE BARRIER MISSILE BARRIER SHELTER SR SUPPORT NSR SUPPORT SR
DOORS/INDOOR - ALL: ALL DOORS THROUGHOUT THE BUILDING	FIRE BARRIER FLOOD BARRIER HELB SHIELDING
ELASTOMER/BORATED WATER - ALL: SFP GATES	PRESSURE BOUNDARY
ELASTOMERS/INDOOR-ALL RUBBER SILL, SWEEP-FLOOD DOORS	FLOOD BARRIER
GROUT/INDOOR - ALL: COLUMNS BASEPLATES; MISCELLANEOUS STEEL STRUCTURES	SUPPORT NSR SUPPORT SR
MASONRY BLOCK WALL/INDOOR - ALL: BLOCK WALLS (8', 26', 46' EL)	FIRE BARRIER SHELTER SR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: STRUCTURAL STEEL FRAMING	SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL PILES/BURIED - ALL: SPENT FUEL POOL	SUPPORT SR

Table 2.4.6-1 Primary Auxiliary Building Structure

Component Group	Intended Function
STRUCTURAL CARBON STEEL/INDOOR -ALL: CRANE SUPPORT GIRDERS; FRAMING - COLUMNS, BEAMS; ROOF TRUSS; PLATFORMS, STAIRS	DIRECT FLOW SHELTER SR SUPPORT NSR SUPPORT SR
STRUCTURAL STAINLESS STEEL/BORATED WATER - ALL: SPENT FUEL POOL; SFP CANAL; SFP GATES	PRESSURE BOUNDARY
STRUCTURAL STAINLESS STEEL/BORATED WATER - ALL: SPENT FUEL STORAGE RACKS	SUPPORT SR
STRUCTURAL STAINLESS STEEL/INDOOR - ALL: NEW FUEL STORAGE RACKS	SUPPORT NSR

2.4.7 Turbine Building Unit 1/2 Structure

Description

The Unit 1 and Unit 2 Turbine Buildings (TBs) are rectangular, non-safety related, seismic Class 3 structures that are constructed from structural steel and reinforced concrete with internal bracing provided by structural steel columns and beams. The TBs are adjacent to the Primary Auxiliary Building (PAB). The TBs are inline, with Unit 1 building being south of Unit 2 building and their Unit 1 to Unit 2 interface being over the Control Building (CB). The TBs enclose the CB, except for the CB's east and west walls. Lateral bracing exists between the TB's structural steel framing and the adjacent seismic Class 3 PAB's steel superstructure and South Service Building steel framing. The TBs have no fixed structural attachments with the adjacent seismic Class I structures, CB and PAB (lower reinforced concrete portion).

The TBs' basemats, elevation 8'-0", and foundation footings consist of reinforced concrete supported on compacted subgrade. The TBs' intermediate floors, at elevations 26'-0" and 44'-0", consist of either reinforced concrete on metal decking or metal grating. The intermediate floors are supported by the buildings' structural steel columns and beams. The TBs' roofs, elevation 109'-0" (nominal), are supported by interconnected structural steel trusses. The TBs' exterior consists primarily of metal wall panels.

Since some SSCs in the Turbine Building Unit 1/2 Structure are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Turbine Building Unit 1/2 Structure containing components subject to an AMR include the walls, roof, foundations, floors, ceilings, beams, and columns.

System Function Listing

A comprehensive listing of functions associated with the Turbine Building Unit 1/2 Structure, or specific components contained in the structure, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The non-safety related, Seismic Class III TBs provide support and housing to non-safety related equipment, whose failure would not adversely affect safety related equipment or equipment functions. This equipment includes the main turbine generator, its auxiliaries and support equipment.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: The non-safety related, Seismic Class III TBs' structural steel frame and foundation provide support to safety related and non-safety related SSCs, whose failure could adversely affect safety related functions. These TB SSCs include items such as the building's support for the safety related Main Steam and Feedwater valves, overhead crane (NUREG-0612), Non-Vital Switchgear Area north wall HELB shield (Unit 2 only), and CR ventilation air intake ducting (Control Room habitability).

Code Z1	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 (FP/APP R)- CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)			FP	EQ	PTS	AT	SB
			X				

Comment: The non-safety related, Seismic Class III TB contains SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site’s implementation of Fire Protection regulations. The TB includes structures such as concrete (LO curbs) and masonry concrete block walls (LO Storage Room).

FSAR Reference

Additional Turbine Building Unit 1/2 Structure details are provided in Section 2.5, Section 2.6, and Section 2.8 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Turbine Building Unit 1/2 Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Turbine Building Unit 1/2 Structure that require aging management review are addressed in Table 2.4.7-1 along with each component group’s intended function(s).

Table 2.4.7-1 Turbine Building Unit 1/2 Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - SPREAD FOOTINGS AND BASEMAT; FLOOR	SUPPORT NSR SUPPORT SR

Table 2.4.7-1 Turbine Building Unit 1/2 Structure

Component Group	Intended Function
CONCRETE/INDOOR - ALL: FLOORS AND WALLS (NORTH, 8', 26' EL); TURBINE GENERATOR LO RESERVOIR AREA CURBING; LO STORAGE TANK AREA WALLS	FIRE BARRIER SUPPORT NSR SUPPORT SR
CONCRETE/OUTDOOR - ALL: FOUNDATION WALLS	SUPPORT NSR SUPPORT SR
GROUT/INDOOR - ALL: COLUMN BASEPLATES	SUPPORT NSR SUPPORT SR
MASONRY BLOCK WALLS/INDOOR - ALL: LO STORAGE ROOM WALLS (UNIT 2 ONLY)	FIRE BARRIER
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: STRUCTURAL STEEL FRAMING; HELB BARRIERS; FLOOD LOUVERS; ROLLUP DOOR BRACES	SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL/INDOOR - ALL: FLOOD LOUVERS - EAST WALL; DOOR BRACING - EAST WALL; HELB BARRIER - NORTH WALL; CRANE RAILS SUPPORTS; FRAMING - COLUMNS, BEAMS; ROOF TRUSS	SUPPORT NSR SUPPORT SR

2.4.8 Yard Structures

Description

Yard Structures includes electrical manholes and duct banks, tank foundations, SBO equipment foundations, and earthen berm barrier.

Electrical manholes and duct banks contain safety related and non-safety related cables. Manholes are a reinforced concrete box-type structure with a reinforced concrete or cast iron cover. Duct banks are reinforced concrete structures that encase galvanized steel and PVC pipes which act as conduit for the electrical cables.

In-scope SBO components include electrical distribution items needed for coping and power restoration. Typical yard structures are the equipment foundations, pads, and support structures The gas turbine generator fuel oil tank foundations and surrounding earthen berm are also included.

Other miscellaneous yard structures, such as the sewer sub-system components (e.g., catch basins, head walls, manholes), road systems (e.g. parking lots, roads, curbs, sidewalks), fencing and gates, yard transformer and tower concrete foundations, lagoons and drainage ditches, concrete security barriers, utility poles, transformer fire walls, and lake bank stabilization materials (e.g., rip-rap), are not in the scope of license renewal.

The description above results in some SSCs in these structures being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Yard Structures containing components subject to an AMR include the concrete manholes and duct banks, electrical equipment concrete foundations and steel support structures and earthen berms.

System Function Listing

A comprehensive listing of functions associated with the Yard Structures, or specific components contained in the structures, is provided in the summary below.

Code R	Cri 1	Cri 2	Cri 3				
STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS			FP	EQ	PTS	AT	SB
	X						

Comment: Several electrical manholes and their associated duct banks contain safety related cables (those cables prefixed with a 'Z' or 'W'). Electrical systems and components vital to plant safety are designed as Class I, which provides suitable protection against severe external environmental phenomena.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The sewer sub-system (e.g., catch basins, head walls, manholes), road system (e.g. parking lots, curbs, sidewalks), fencing and gates, yard transformer and tower concrete foundations, lagoons and drainage ditches, concrete security barriers, electrical handholes, utility poles, transformer fire walls, and bank stabilization (e.g., rip-rap) are not within the scope of license renewal. Most yard structures, except those specifically identified Yard Structures assets consisting of a limited number of manholes, duct banks, electrical equipment concrete pads, and electrical disconnect support structures, are not within the scope of license renewal.

Code Z1 LICENSE RENEWAL CRITERION 3 (FP/APP R)-CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: Yard Structures assets (e.g., manholes and associated duct banks) directly support the ability of the Gas Turbine Generator (G05) to alternately power safe shutdown loads for fire scenarios in the Control Room, the Cable Spreading Room, or the Vital Switchgear Room. The G05 and its associated electrical distribution from G05 to transformer X08 via the 13.8K VAC Bus H01 in the 13.8 KV Switchgear Building Structure are relied upon in safety analyses and plant evaluations for alternate shutdown power. The fuel oil tank earthen berm confines flammable liquid.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: YARD assets (e.g., manholes and associated duct banks, electrical equipment pads, electrical distribution disconnect switch support structure and pads) directly support the ability of the Gas Turbine Generator (G05) to power safety related buses 1/2-A05 and 1/2-A06 through the onsite 13.8K VAC and 4160 VAC electrical distribution systems. YARD assets also support offsite power restoration through portions of the offsite 345K VAC and the offsite 13.8K VAC electrical distribution systems. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s coping with a station blackout.

FSAR Reference

Additional Yard Structures details are provided in Section 1.3, Section 2.5, Section 2.6, Section 2.8, and Section 8.0.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Yard Structures are listed below:

Common
LR-E-100, Sh. 1
LR-6704-E-353401

Components/Commodities Subject to an AMR

The component groups for the Yard Structures that require aging management review are addressed in Table 2.4.8-1 along with each component group's intended function(s).

Table 2.4.8-1 Yard Structures

Component Group	Intended Function
CONCRETE/BURIED - ALL: ELECTRICAL DUCT BANKS; EQUIPMENT FOUNDATIONS AND SUPPORT PADS; MANHOLES	SHELTER SR SUPPORT NSR SUPPORT SR
CONCRETE/INDOOR - ALL: MANHOLE INTERIOR	SHELTER SR SUPPORT NSR SUPPORT SR
CONCRETE/OUTDOOR -ALL: EQUIPMENT FOUNDATIONS AND SUPPORT PADS; MANHOLES AND COVERS	FIRE BARRIER SHELTER SR SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL FASTENERS/OUTDOOR - ALL: SWITCHYARD EQUIPMENT FRAMES	SUPPORT NSR

Table 2.4.8-1 Yard Structures

Component Group	Intended Function
STRUCTURAL CARBON STEEL/OUTDOOR - ALL: MANHOLE COVERS; FRAMING - 345K VAC DISTRIBUTION SYSTEM; BUS DUCTS - HVSATS TO CIRCUIT BREAKER CABINETS; BUS DUCTS - LVSATS TO 13.8K VAC SWITCHGEAR CABINET	SUPPORT NSR
STRUCTURAL CAST IRON/OUTDOOR - ALL: MANHOLE FRAMES AND COVERS	FIRE BARRIER SHELTER SR SUPPORT NSR

2.4.9 Cranes, Hoists, and Lifting Devices

Description

The Cranes, Hoists, and Lifting Devices System consists of fuel handling cranes and the load handling systems that comply with NUREG-0612. The fuel handling cranes include the reactor cavity manipulator cranes and the SFP bridge crane. Fuel handling cranes are not within the scope of license renewal for they have no intended function, i.e., they are not safety related or heavy load capacity. The NUREG-0612 load handling systems include the Containment Cranes, the Auxiliary Building Main Crane, and the Turbine Building Overhead Crane. This LR system also includes the Emergency Diesel Generator G03 and G04 Cranes and Monorails (Diesel Generator Building), the RCP Lifting Slings, and the Reactor Vessel Head and Internals Lifting Rigs. The specific components comprising this LR system are the structural members (bridge and trolley) of these heavy load cranes and lifting devices, including the crane rails and hardware.

These load-handling systems were identified to have the potential for a heavy load drop, which could result in damage to safe shutdown equipment. The remainder of the cranes, hoists, and lifting devices are excluded due to their load carrying capacity (being less than that of a heavy load) or their lack of proximity to safe shutdown equipment. The boundary for the Cranes, Hoists, and Lifting Devices System is limited to the load-bearing components that structurally support the heavy loads in a passive manner. This includes the bridge and trolley items such as structural beams, girders, and rails. All other components of the Cranes, Hoists, and Lifting Devices System are considered active or have no component-level intended functions. This includes, but is not limited to, control panels, lights, switches, terminal boxes, motors, cameras, brakes, gears, and cables.

Since some SSCs in the Cranes, Hoists, and Lifting Devices System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2).

The portions of the Cranes, Hoists, and Lifting Devices System containing components subject to an AMR include the bridge and trolley structural beams, girders, and rails associated with NUREG-0612 heavy load cranes and lifting devices.

System Function Listing

A comprehensive listing of functions associated with the Cranes, Hoists, and Lifting Devices System, or specific components contained in the system, is provided in the summary below.

Code Y	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION			FP	EQ	PTS	AT	SB
		X					

Comment: By definition of NUREG 0612, the safe handling of heavy loads is a non safety affecting safety function or the load handing systems are required to meet single failure proof criteria.

FSAR Reference

Limited Cranes, Hoists, and Lifting Devices System details are provided in Section 9.4 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Cranes, Hoists, and Lifting Devices System are listed below:

<u>Common</u>
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Cranes, Hoists, and Lifting Devices System that require aging management review are addressed in Table 2.4.9-1 along with each component group's intended function(s).

Table 2.4.9-1 Cranes, Hoists, and Lifting Devices

Component Group	Intended Function
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: RAIL HARDWARE	SUPPORT NSR
STRUCTURAL CARBON STEEL/INDOOR - ALL: BRIDGE AND TROLLEY FRAMING; CRANE RAILS, MONORAILS; LIFTING RIGS	SUPPORT NSR
STRUCTURAL STAINLESS STEEL/BORATED WATER - ALL: RV INTERNALS LIFTING RIG	SUPPORT NSR

2.4.10 Component Supports Commodity Group

Description

The Component Supports (CSUP) commodity contains component and equipment supports, pipe restraints, electrical raceways, and electrical enclosures associated with Unit 1, Unit 2, and Common plant systems and equipment. This commodity group includes the grout under the base-plate and fasteners used with the support or equipment anchorage.

Generally, supports provide the connection between a system's equipment or component and a plant structural member (e.g., wall, floor, ceiling, column, beam). They provide support for distributed loads (e.g., piping, tubing, HVAC ducting, conduit, cable trays) and localized loads (e.g., individual equipment). Specific types of equipment and components evaluated as part of this commodity group include:

- Raceways - Generic component type that is designed specifically for holding electrical wires and cables, such as cable trays, exposed and concealed metallic conduit or wireways. Commodity assets for raceways include both the component and the component's support and attachment. Underground ducts, a type of raceway, are included with Yard Structures.

- Electrical Enclosures - Generic component type that contains electrical components such as panels, boxes, cabinets, consoles, and bus ducts. An electrical enclosure includes both the enclosure and its supports and attachments.
- Pipe Supports - Includes all items used to support piping. The support boundary includes all the auxiliary steel back to the structure's surface.
- Pipe Restraints - Failure and seismic restraints that limit pipe movement during postulated events. Includes structural steel and fasteners (e.g., bolts, studs, nuts).
- Equipment Supports - Includes structural steel, fasteners (e.g., bolts, studs, nuts), and vibration mounts that secure equipment to structures.
- HVAC Duct Supports - Includes structural steel and fasteners (e.g., bolts, studs, nuts) that support/attach ventilation duct to structures.

The CSUP commodity group excludes jet impingement barriers (e.g., High Energy Line Break barriers), and miscellaneous plant structures and their details (e.g., stairs, platforms, crane rails). These items were evaluated with the structure where they are located.

The description above results in some SSCs in this group being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Component Supports Commodity Group are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2).

The portions of the Component Supports Commodity Group containing components subject to an AMR include component and equipment supports, pipe restraints, electrical raceways, and electrical enclosures.

System Function Listing

A comprehensive listing of functions associated with the Component Supports Commodity Group, or specific components contained in the group, is provided in the summary below.

Code R STRUCTURALLY SUPPORT OR HOUSE SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Component Supports commodity group provides structural support, including the fasteners and anchorages, for safety related system piping, ventilation ducting, raceways, and equipment. This commodity group also contains electrical enclosures and raceways that can house safety related system electrical components.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Component Supports commodity group provides structural support to non-safety related system piping, ventilation ducting, raceways, and equipment, whose failure would not prevent satisfactory accomplishment of safety related functions.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: Component Supports commodity group provides structural support, including the fasteners and anchorages, for non-safety related system piping, ventilation ducting, raceways, and equipment, whose failure could prevent satisfactory accomplishment of station blackout, fire protection, or safety related functions.

FSAR Reference

Additional Component Supports Commodity Group details are provided in Section 2.6, Section 5.1.1.1, and Figure 2.6-1 of the FSAR.

License Renewal Drawings

None.

Components/Commodities Subject to an AMR

The component groups for the Component Supports Commodity Group that require aging management review are addressed in Table 2.4.10-1 along with each component group's intended function(s).

Table 2.4.10-1 Component Supports Commodity Group

Component Group	Intended Function
ELASTOMER/INDOOR - ALL: EQUIPMENT MOUNT VIBRATION ISOLATORS	SUPPORT NSR SUPPORT SR
GROUT/INDOOR - ALL: EQUIPMENT AND SUPPORTS BASEPLATES	SUPPORT NSR SUPPORT SR
GROUT/OUTDOOR - ALL: EQUIPMENT AND SUPPORTS BASEPLATES	SUPPORT NSR
HIGH STRENGTH STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: HIGH STRENGTH STRUCTURAL FASTENERS - RCS COMPONENT SUPPORTS	SUPPORT SR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: ASME EQUIPMENT; ASME PIPE SUPPORTS AND RESTRAINTS	PIPE WHIP RESTRAINT SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL FASTENERS/INDOOR - ALL: EQUIPMENT SUPPORTS - PIPE RESTRAINTS, MECHANICAL EQUIPMENT, HVAC DUCTS, PANELS AND CABINETS; RACEWAYS; MISCELLANEOUS STEEL STRUCTURES	PIPE WHIP RESTRAINT SUPPORT NSR SUPPORT SR

Table 2.4.10-1 Component Supports Commodity Group

Component Group	Intended Function
STRUCTURAL CARBON STEEL FASTENERS/OUTDOOR - ALL: G01/02 EXHAUST STACK, EQUIPMENT SUPPORTS - YARD	SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL/INDOOR - ALL: ASME PIPE SUPPORTS AND RESTRAINTS; ASME EQUIPMENT SUPPORTS	PIPE WHIP RESTRAINT SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL/INDOOR - ALL: FRAMING - STRUCTURAL SHAPES; NON-ASME PIPE SUPPORTS AND RESTRAINTS; NON-ASME EQUIPMENT SUPPORTS; HVAC DUCT SUPPORTS; RACEWAYS - CABLE TRAYS, METALLIC CONDUIT, WIREWAYS; ELECTRICAL ENCLOSURES - PANELS, BOXES, CABINETS, CONSOLES	PIPE WHIP RESTRAINT SUPPORT NSR SUPPORT SR
STRUCTURAL CARBON STEEL/OUTDOOR - ALL: G01/02 EXHAUST STACK, EQUIPMENT SUPPORTS - YARD	SUPPORT NSR SUPPORT SR
STRUCTURAL STAINLESS STEEL FASTENERS/INDOOR - ALL: EQUIPMENT/COMPONENT ATTACHMENTS (PRIMARILY NSSS)	SUPPORT NSR SUPPORT SR
STRUCTURAL STAINLESS STEEL/INDOOR - ALL: STRUCTURAL SHAPES (PRIMARILY NSSS AND TUBING)	SUPPORT NSR SUPPORT SR

2.4.11 **Fire Barrier Commodity Group**

Description

The Fire Barriers (FIRE) commodity group includes all fire stops and fire wraps used throughout the site that are credited in the Fire Protection Evaluation Report. Fire stops are the fire barrier penetration seals and cable tray fire stops. Fire wraps are an envelope system installed around electrical components, conduits, and cabling to maintain safe shutdown functions free of fire damage. In addition, structural steel member fire proofing would be considered a fire wrap.

Fire stops provide a fire resistance equivalent to the rating of the fire barrier in order to prevent the spreading of fire to adjacent fire areas or fire zones. Penetration seals are used to close openings in ceilings, floors, and walls. These openings may be electrical (e.g., cables, cable trays, conduits) or mechanical penetrations (e.g., pipes, instrument lines, ventilation ducts). Cable tray fire stops are a type of barrier that prevents the propagation of fire along the length of cables. Fire wrap is used to fulfill separation requirements between electrical trains when physical separation is restricted by spatial design considerations. Fire doors, curbs, dikes, structural fire proofing, and hollow concrete block walls are evaluated as part of the structure where they are located. Fire damper housings (e.g., through-wall and in-duct) are included here (scoped and screened independently). Fire detection and alarm (e.g., smoke detectors), and fire suppression (e.g., automatic sprinklers, automatic halon systems) are evaluated in the Fire Protection System.

The description above results in some SSCs in this group being considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Fire Barrier Commodity Group containing components subject to an AMR include fire barrier penetration seals, cable tray fire stops, and fire wraps.

System Function Listing

A comprehensive listing of functions associated with the Fire Barrier Commodity Group, or specific components contained in the group, is provided in the summary below.

Code Z1	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
LICENSE RENEWAL CRITERION 3 (FP/APP R)- CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)			X				

Comment: Fire Areas and their boundaries, have been identified and analyzed and determined to provide sufficient protection to prevent the spread of a fire beyond the boundaries. The Fire Barriers Commodity Group contains those items that are a part of and are credited in a fire boundary.

FSAR Reference

None.

License Renewal Drawings

None.

Components/Commodities Subject to an AMR

The component groups for the Fire Barrier Commodity Group that require aging management review are addressed in Table 2.4.11-1 along with each component group’s intended function(s).

Table 2.4.11-1 Fire Barrier Commodity Group

Component Group	Intended Function
CALCIUM SILICATE BOARD/INDOOR - ALL: CABLE TRAYS - FIRE STOP; PENETRATION SEALS	FIRE BARRIER
CERAMIC FIBER/INDOOR - ALL: CABLE TRAYS - FIRE STOP; PENETRATION SEALS	FIRE BARRIER

Table 2.4.11-1 Fire Barrier Commodity Group

Component Group	Intended Function
CERAMIC FIBER-BOARD/ INDOOR - ALL: PENETRATION SEALS	FIRE BARRIER
CERAMIC FIBER-MAT/INDOOR - ALL: CABLE TRAYS - FIRE STOP	FIRE BARRIER
SILICONE BASED MATERIAL/INDOOR - ALL: SPRAYED ON MASTIC; CABLE TRAYS - FIRE STOP; PENETRATION SEALS	FIRE BARRIER
STAINLESS STEEL APPURTENANCES/INDOOR - ALL: TAPE, BANDING, BANDING SEALS, AND WIRE FOR FIRE WRAPS AND PENETRATION SEALS	FIRE BARRIER
STRUCTURAL CARBON STEEL/INDOOR - ALL: FIRE DAMPER FRAMES; CABLE TRAY COVERS	FIRE BARRIER

2.4.12 **13.8 KV Switchgear Building Structure**

Description

The 13.8 KV Switchgear Building Structure is a rectangular, non-safety related, seismic Class 3, concrete and masonry block structure. The building is an independent structure with no other buildings in its immediate vicinity. The 13.8 KV Switchgear Building Structure houses non-safety related electrical equipment, including 13.8K VAC Buses H01, H02, and H03 and 13.8K VAC Circuit Breakers H52-10, H52-20, H52-21, H52-30, and H52-31. The Gas Turbine Generator electrical power is supplied to the 13.8K VAC Power System via Circuit Breaker H52-10 and tie Bus H01. G05 is relied upon as the Alternate AC (AAC) power source during a station blackout (SBO) and is relied upon to supply power to safe shutdown loads through the alternate shutdown equipment during a fire in 4160 VAC switchgear.

The 13.8 KV Switchgear Building Structure consists of a single level, which is divided into three separate rooms by 8" masonry block walls. The foundation consists of spread reinforced concrete footings and a reinforced concrete basemat that provides the operating floor at elevation 26'-6". The building's perimeter walls are constructed of both poured reinforced concrete and masonry block. The roof is a concrete slab. The west wall (rear) and portions or the north and south walls of the building are set into an earthen embankment. The in-scope boundary for the building includes the reinforced concrete foundation slab and switchgear anchors. The remaining portions of the structure, including the interior walls, exterior masonry block and concrete walls, and roof are not within the scope of license renewal.

Some SSCs in the13.8 KV Switchgear Building Structure are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the 13.8 KV Switchgear Building Structure containing components subject to an AMR include the foundation and equipment supports.

System Function Listing

A comprehensive listing of functions associated with the 13.8 KV Switchgear Building Structure, or specific components contained in the structure, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The 13.8 KV Switchgear Building Structure provides support and housing to non-safety related equipment, whose failure would not adversely affect safety related equipment or equipment functions. The building accommodates access control attributes and appearance (cosmetic/aesthetic) consistent with other site buildings.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The 13.8 KV Switchgear Building Structure's reinforced concrete basemat and floor provide support for 13.8K VAC power distribution electrical equipment that would be used to route electrical power from the Gas Turbine Generator (G05) to plant loads. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site's coping with a station blackout and the site's ability to alternately power safe shutdown loads with a fire in the 4160 VAC switchgear.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The 13.8 KV Switchgear Building Structure's reinforced concrete basemat and floor provide support for 13.8K VAC power distribution electrical equipment that would be used to route electrical power from the Gas Turbine Generator (G05) to plant loads. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site's coping with a station blackout and the site's ability to alternately power safe shutdown loads with a fire in the 4160 VAC switchgear.

FSAR Reference

Additional 13.8 KV Switchgear Building Structure details are provided in Section 8.2, Section 8.9, Appendix A.1, and Appendix A.5 of the FSAR.

License Renewal Drawings

The license renewal drawings for the 13.8 KV Switchgear Building Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the 13.8 KV Switchgear Building Structure that require aging management review are addressed in Table 2.4.12-1 along with each component group's intended function(s).

Table 2.4.12-1 13.8 KV Switchgear Building Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - SPREAD FOOTING AND BASEMAT	SUPPORT NSR
CONCRETE/INDOOR - ALL: FLOOR (INTEGRAL WITH BASEMAT)	SUPPORT NSR
CONCRETE/OUTDOOR - ALL: FOUNDATION - SPREAD FOOTING AND BASEMAT	SUPPORT NSR

2.4.13 **Fuel Oil Pumphouse Structure**

Description

The Fuel Oil Pumphouse (FOPH) Structure is a rectangular, safety related, seismic Class I structure constructed from reinforced concrete and concrete masonry block. This building is an independent structure with no other structures in its immediate vicinity. The FOPH building houses non-safety related mechanical and electrical equipment, including the Gas Turbine Fuel Oil Supply Pump, which is required for Gas Turbine Generator (G05) operation. G05 is relied upon as the Alternate AC (AAC) power source during a station blackout (SBO) and is relied upon to supply power to safe shutdown loads through the alternate shutdown equipment during a fire in 4160 VAC switchgear.

The FOPH Structure consists of several areas on two levels. Below grade, the building consists of reinforced concrete floor (basemat), walls, and ceiling. Above grade, the building is predominately concrete masonry block, except for the reinforced concrete floor and stairwell enclosure and the concrete slab roof. The building's basemat is at elevation

5'-0", the intermediate floor is at elevation 25'-6", and the concrete roof is at elevation 35'-4" (nominal). The in-scope boundary for the FOPH includes the ground floor and basement area, which are comprised of reinforced concrete. The above grade block wall portion of the superstructure, including the roof, is not within the scope of license renewal.

Some SSCs in the Fuel Oil Pumphouse Structure are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Fuel Oil Pumphouse Structure containing components subject to an AMR include the foundations and equipment supports.

System Function Listing

A comprehensive listing of functions associated with the Fuel Oil Pumphouse Structure, or specific components contained in the structure, is provided in the summary below.

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: The FOPH provides support and housing to non-safety related equipment, whose failure would not adversely affect safety related equipment or equipment functions. The FOPH building accommodates access control attributes, provides a facility for fuel oil storage and transfer equipment, and appearance (cosmetic/aesthetic) consistent with other site buildings.

Code Z1	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)			FP	EQ	PTS	AT	SB
			X				

Comment: The FOPH’s reinforced concrete basemat, walls, and floor provide support for the Gas Turbine Fuel Oil Supply Pump (P105), which is required for Gas Turbine Generator (G05) operation. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s coping with a station blackout and the site’s ability to alternately power safe shutdown loads with a fire in the 4160 VAC switchgear. The support function provided by the FOPH would be considered a second-level support SSC under guidance provided in the NUREG-1800 (Standard Review Plan for LR) since it only provides support for the fuel oil supply to G05. Therefore, it would not have been necessary to include this function as a system-level intended function.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The FOPH’s reinforced concrete basemat, walls, and floor provide support for the Gas Turbine Fuel Oil Supply Pump (P105), which is required for Gas Turbine Generator (G05) operation. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s coping with a station blackout and the site’s ability to alternately power safe shutdown loads with a fire in the 4160 VAC switchgear. The support function provided by the FOPH would be considered a second-level support SSC under guidance provided in the NUREG-1800 (Standard Review Plan for LR) since it only provides support for the fuel oil supply to G05. Therefore, it would not have been necessary to include this function as a system-level intended function.

FSAR Reference

Additional Fuel Oil Pumphouse Structure details are provided in Section 8.9 and Appendix A.5 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Fuel Oil Pumphouse Structure are listed below:

<u>Common</u>
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Fuel Oil Pumphouse Structure that require aging management review are addressed in Table 2.4.13-1 along with each component group’s intended function(s).

Table 2.4.13-1 Fuel Oil Pumphouse Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - BASEMAT; WALLS	SUPPORT NSR

Table 2.4.13-1 Fuel Oil Pumphouse Structure

Component Group	Intended Function
CONCRETE/INDOOR - ALL: CEILING (25'-6'' EL)	SUPPORT NSR
CONCRETE/OUTDOOR - ALL: FOUNDATION - BASEMAT	SUPPORT NSR

2.4.14 Gas Turbine Building Structure

Description

The Gas Turbine Building (GTB) Structure is a rectangular, non-safety related, seismic Class 3 structure that is constructed from prefabricated metal wall and roof panels attached to a structural steel frame. The building's structural steel frame is supported by a reinforced concrete basemat and foundation. The building is an independent structure with no other buildings in its immediate vicinity. The GTB houses non-safety related Gas Turbine Generator (G05) and its associated mechanical and electrical equipment. G05 is relied upon as the Alternate AC (AAC) power source during a station blackout (SBO) and is relied upon to supply power to safe shutdown loads through the alternate shutdown equipment during a fire in 4160 VAC switchgear.

The GTB consists of a single compartment. The building's basemat, building elevation 0'-0" and foundation footings consist of reinforced concrete supported on compacted subgrade. Equipment foundations are integral with the building's basemat. The building's roof is at building elevation 16'-11" (nominal). The in-scope boundary for the GTB includes the concrete foundation slab and the turbine-generator concrete equipment pedestals. The remaining portions of the structure, which include the steel superstructure, are not within the scope of license renewal.

Some SSCs in the Gas Turbine Building Structure are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Gas Turbine Building Structure containing components subject to an AMR include the foundations and equipment pedestals.

System Function Listing

A comprehensive listing of functions associated with the Gas Turbine Building Structure, or specific components contained in the structure, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The GTB provides support and housing to non-safety related equipment, whose failure would not adversely affect safety related functions. The GTB provides an enclosure to shield Gas Turbine Generator (G05) and associated support equipment from outdoor weather conditions, and appearance (cosmetic/aesthetic) consistent with other site buildings.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The GTB’s reinforced concrete basemat and equipment foundations provide support for the Gas Turbine Generator and associated direct support equipment. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s coping with a station blackout and the site’s ability to power safe shutdown loads with a fire in 4160 VAC switchgear.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The GTB’s reinforced concrete basemat and equipment foundations provide support for the Gas Turbine Generator and associated direct support equipment. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s coping with a station blackout and the site’s ability to power safe shutdown loads with a fire in 4160 VAC switchgear.

FSAR Reference

Additional Gas Turbine Building Structure details are provided in Section 8.9 and Appendix A.5 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Gas Turbine Building Structure are listed below:

Common
LR-C-3

Components/Commodities Subject to an AMR

The component groups for the Gas Turbine Building Structure that require aging management review are addressed in Table 2.4.14-1 along with each component group's intended function(s).

Table 2.4.14-1 Gas Turbine Building Structure

Component Group	Intended Function
CONCRETE/BURIED - ALL: FOUNDATION - BASEMAT	SUPPORT NSR
CONCRETE/INDOOR - ALL: FLOOR; EQUIPMENT PEDESTALS	SUPPORT NSR
CONCRETE/OUTDOOR - ALL: FOUNDATION - BASEMAT	SUPPORT NSR

2.5 Scoping and Screening Results: Electrical and Instrumentation and Controls

The following systems and commodity groups are addressed in this section:

- Commodity Group Descriptions (Section 2.5.1)
- 120 VAC Vital Instrument Power System (Section 2.5.2)
- 125 VDC Power System (Section 2.5.3)
- 4160 VAC Power System (Section 2.5.4)
- 480 VAC Power System (Section 2.5.5)
- Control Rod Drive and Indication and Nuclear Process Instrumentation System (Section 2.5.6)
- Miscellaneous AC Power and Lighting System (Section 2.5.7)
- Offsite Power System (Section 2.5.8)
- Reactor Protection System (includes AMSAC) (Section 2.5.9)
- Engineered Safety Features Actuation System (Section 2.5.10)
- Plant Communications System (Section 2.5.11)
- 13.8K VAC Power System (Section 2.5.12)
- Radiation Monitoring System (Section 2.5.13)

The scoping and screening process of the integrated plant assessment, as applied to all of the PBNP electrical power, communications, and I&C systems, resulted in most power systems and some I&C systems being included in-scope for license renewal. This is documented in the individual system scoping and screening reports. Boundary definitions excluded electrical equipment which was not safety related, whose failure did not prevent a safety related (SR) system from performing its SR function, and which did not support a LR required regulated event. When the remaining equipment was examined and screened for active or passive functions, the majority of the components were determined to be active per Appendix B of NEI 95-10 and screened out of LR scope. The remaining components were categorized into the following passive commodities:

- Non-EQ power, instrumentation, control and communication insulated cables and connections (connections include connectors, splices, fuse holders, and terminal blocks)
- Electrical portions of non-EQ electrical and I&C penetration assemblies
- Phase bus (Specific types used at PBNP, such as isolated-phase bus, non-segregated-phase bus, and segregated-phase bus, are described.)
- Switchyard bus
- Transmission conductors

- High-voltage insulators
- Uninsulated ground conductors (Not in LR scope)
- Panels and junction boxes

2.5.1 Commodity Group Descriptions

Insulated Cables and Connections

Cables are associated with equipment in almost every plant system. There are approximately 28,000 installed cables at PBNP, Units 1 and 2. Electrical cables and connections were treated as a commodity group during the aging management review process. This commodity group included all cables within the scope of license renewal that are used for power, control and instrumentation applications. The intended function of electrical cables and connections is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals.

Cable insulation material groups were assessed on the basis of common materials and their respective material aging characteristics for both safety related and non-safety related cables.

According to the Department of Energy Cable Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Terminations (Reference 1), an insulated cable is an assembly of a single electrical conductor (wire) with an insulation covering or a combination of conductors insulated from one another with overall coverings. Connections (or terminations) are used to connect the cable conductors to other cables or electrical devices. Those cables and connections reviewed are non-EQ power, instrumentation, control and communication insulated cables and connections (connections include connectors, splices, terminal blocks, and fuse holders). The types of connections are compression, fusion, plug-in connectors, splices, and terminal blocks. Compression and fusion connections involve various types of metals and other inorganic materials that have no aging effects that would result in loss of intended function. Compression and fusion connections are therefore not reviewed.

Insulated cables and connections that were given an aging management review are those that are not part of some larger, active component (e.g., cables internal to motors, switchgear, relays, transformers, power supplies, inverters, chargers, or control panels) since cables and connections that are part of these components are maintained and inspected as part of the active component. Included in the cable commodity are specific component cooling pump motor cables reserved for response to Appendix R scenarios and stored in warehouse space outside of the plant.

Since the intended functions, materials, and construction of the cables and connections are similar or identical across all uses, this commodity includes non-EQ cables and connections used in instrumentation circuits that are sensitive to reduction in insulation resistance (specifically Nuclear Process Instrumentation System and Radiation Monitoring System cables that are not already EQ) and non-EQ medium-voltage cables and connections, both accessible and inaccessible. However, the environments, aging effects, and aging management activities for the cables in these two categories are considered separately from other non-EQ cables.

The plant Cable And Raceway Data System (CARDS) was used as the primary tool to identify cable insulation groups and for screening electrical cables for the cables aging management review. The database contains a basic cable data code. The basic cable data code defines a unique cable type using data fields that include vendor, number of conductors and their size, application (power, control, and instrumentation), insulation, and jacket. Cable insulation groups and the associated application were the determining factors in performing the assessment against bounding plant parameters.

Electrical cables were reviewed as a commodity group for all in-scope systems. The electrical cable aging management review for radiation and temperature utilized a plant “spaces” approach, whereby aging effects were identified, and bounding environmental parameters for in-scope plant spaces were used to evaluate the identified aging effect(s) with respect to component intended function.

This commodity group also includes electrical connectors, splices, fuse holders, and terminal blocks used for power, control and instrumentation applications. Components in this commodity group that are part of the Environmental Qualification Program were evaluated by Time-Limited Aging Analyses.

The electrical connector materials subject to aging are metal and insulation. The metals used for electrical connectors are copper, tinned copper, and aluminum. The connector insulation materials used are various elastomers and thermoplastics, and are bounded by the cable aging management review.

The splice material subject to aging is insulation. The insulation materials used are various elastomers, and are bounded by the cables aging management review.

The electrical terminal block and fuse holder materials subject to aging are metal and insulation. The metals used for terminal blocks are copper, tinned copper, brass, and bronze. The insulation materials used are phenolic compounds and nylon.

Electrical Penetration Assemblies

The non-EQ electrical and I&C penetration assemblies of the original plant design are of the same construction as the EQ electrical and I&C penetration assemblies of that design. They were installed at the same time and to the same standards. Since they are maintained to the same standards, their lifetimes for license renewal purposes are bounded by the TLAAs performed for the electrical and I&C penetration assemblies in the EQ Program. The organic materials included in the assemblies as insulation and/or pigtails connected to the through conductors are considered in the insulated cable and connector portion of the electrical commodities. The post-TMI and later penetration assemblies were purchased, installed, and are maintained as EQ penetrations.

Numerous electrical power and instrumentation and control (I&C) systems penetrate the containment wall through welded steel penetrations. The pressure boundary components and materials of these penetrations are considered as part of the containment structural LR evaluation. There are two general areas for electrical containment penetrations located approximately 38 ft. apart. Each one of the two areas contains one of the trains for engineered safeguards service and two of the four channels of instrumentation (for reactor protection and safeguards). Within each area, penetrations for safeguards or protection are located below the penetrations for nonessential services. Outside the containment, safeguards or protection service penetrations lead into two pipe tunnels where nonessential penetrations are located above the concrete tunnel ceilings. The electrical penetrations typically consist of 10” Schedule 80 carbon steel pipe or nozzle, the pressure boundary component, with three types of electrical penetration assemblies attached by welds. Thermal conduction and radiation paths were sufficient to prevent damage to seals or conductors during field welding of the canisters to the containment liner.

Westinghouse provided the first type of penetration assembly of the original plant construction. The electrical portions of the majority of these non-EQ electric power and I&C penetrations consist of copper conductors of appropriate size and configuration for their current or signal carrying requirements, including shielding, spaced in a self-extinguishing epoxy potting compound over a silicone potting compound that provides both physical support of and electrical isolation between the conductors. The epoxy is covered by a phenolic, flame resistant spacer. The inner and outer stainless steel header plates are welded to a stainless steel container, weld ring and monitor ring assembly that is welded to the nozzle. The header plates support the epoxy and silicone compounds and conductors. Silicone rubber fiberglass sleeving covers the conductors between the header plates internal to the assembly. Phenolic, flame resistant spacers cover the epoxy at both ends of the assembly. Higher voltage electrical power penetrations utilize groups of single conductors (250 MCM, 350 MCM, or 750 MCM), each hermetically sealed in ceramic bushings bonded directly to two stainless steel header plates of the same penetration assembly. These high voltage connections end in threaded or bolted connections without any pigtails. The high voltage penetrations therefore have no organic compounds in either the electrical insulation or containment penetration pressure boundary to consider for aging effects requiring management. Pigtails are provided for both inside and outside of containment for connections to the field cabling for the lower voltage power and I&C penetrations. Pigtails are cables of the same or similar materials and construction as the field cables to which they are connected and their aging is considered within the scope of the insulated cable commodity. The terminations of the pigtail conductors to the connectors inside the canister are potted to protect against moisture.

The second type of penetration assembly was purchased from Westinghouse to accommodate the post-TMI modifications to PBNP. These three penetration assemblies per unit consist of a welded stainless steel canister and header plate, with leakage monitoring channel, having the capacity to hold up to three individually configured electrical modules. The module to canister seals consist of two sets of redundant O-rings of differing materials, silicone and EPR. The conductors are potted to provide a pressure boundary, insulate, and protect against moisture intrusion.

The third type of penetration assembly was purchased from Conax to accommodate some later modifications to the plant. These penetration assemblies consist of a stainless steel header plate with a carbon steel extension ring welded to it, up to eighteen (18) feed through modules containing electrical conductors or stainless steel plugs in each position, and a stainless steel support plate for the feed-through modules. The extension ring is welded to a penetration nozzle. The feed-through modules pass through the header plate and are secured and sealed to the header plate with special Conax designed Midlock stainless steel compression fittings. These compression fittings are installed from the in-containment side of the header plate and are concentric with the feed-through modules. The insulated solid electric conductor of the feed-through is sealed in resilient thermoplastic sealants at both ends of a stainless steel tube which is mechanically swaged to provide a homogeneous, double sealed, leakage monitorable module. All electrical conductors are copper. Pigtails are part of the feed-through modules for attachment to the filed cables and are wrapped in fiberglass cloth tape where they are bundled and routed inside the outer portion of the nozzle (outside of the pressure boundary, outside of the containment).

The typical assembly for each type of electrical penetration has two welded headers, leak chase, or channels that permit pressure and leakage tests to be performed simply and reliably both at the shop and after installation. A tap with welded fittings and tubing leading to an external connection and pressure gauge, convenient to the exterior of the containment, is provided for pressurizing and monitoring the integrity of the assembly pressure boundary around the conductors.

Electrical Phase Bus

The phase bus reviewed for license renewal is bus that is enclosed within its own enclosure that is not part of an active component such as a switchgear, load center or motor control center. The description, interfaces and review boundary of three types of phase bus are discussed below: isolated-phase bus, non-segregated-phase bus and segregated-phase bus.

Isolated-Phase Bus

According to IEEE 100-1984 (Reference 2) an isolated-phase (or isophase) bus is an electrical bus in which each phase conductor is enclosed by an individual metal housing separated from adjacent conductor housings by an air space. Isolated-phase bus connects two or more elements of an electrical power circuit and is normally used to connect active electrical components such as generators, breakers and transformers.

At PBNP, isolated-phase bus is associated with the power circuit from the main generators of each unit to their three single-phase step-up (19K VAC to 345K VAC) transformers and each unit's auxiliary transformer, which is a part of that portion of the Offsite Power System which is not within the scope of LR.

Non-Segregated-Phase Bus

According to the IEEE 100-1984 non-segregated-phase bus is electrical bus constructed with all phase conductors in a common metal enclosure without barriers (only air space) between the phases.

Non-segregated-phase bus connects two or more elements of an electrical power circuit and is normally used to connect active electrical components such as switchgear, transformers and switches. The review of non-segregated-phase bus includes only the bus sections between these active electrical components. The bus and connections inside the enclosures of these active electrical components are inspected and maintained along with and as part of the active electrical components and, therefore, meet the definition of an active component as discussed in the statement of considerations that accompanied the license renewal rule. Non-segregated-phase bus interfaces with structural supports, which are reviewed in the structural supports AMR.

At PBNP, non-segregated-phase bus is associated with the following in-scope systems:

- The13.8K VAC Power System, for horizontal bus connections between switchgear cabinets; the gas turbine power output; connections from switchgear to the low-voltage station auxiliary transformers, respectively; connections between the Unit 1 circuit breaker and the high-voltage station auxiliary transformer; and connections between the Unit 2 circuit breaker and the high-voltage station auxiliary transformer.
- The 4160 VAC Power System, for switchgear cabinet vertical bus connections between two floors, and between adjacent sections of the switchgear in the Control Building.
- The 480 VAC Power System, for underfloor horizontal bus connection for unit specific safety related switchgear in the Cable Spreading Room.

Segregated-Phase Bus

According to IEEE 100-1984 segregated-phase bus is an electrical bus in which all phase conductors are in a common metal enclosure, but are segregated by metal barriers between phases. Segregated-phase bus connects two or more elements of an electrical power circuit and is normally used to connect active electrical components such as switchgear, transformers and generators. Currently there is no segregated-phase bus in use at PBNP.

Switchyard Bus

Switchyard bus is uninsulated, unenclosed, rigid electrical conductor (aluminum tubing and fittings) used in switchyards and switching stations to connect two or more elements of an electrical power circuit such as active disconnect (gang) switches and passive transmission conductors. High-voltage station post insulators support the switchyard bus. High-voltage station post insulators are reviewed elsewhere in this document.

The review of switchyard bus includes the switchyard bus and the hardware used to secure the bus to a high-voltage insulator. This includes corona rings and other similar fixtures that are standard design features of the switchyard bus. The bus connection to an active disconnect switch is inspected using thermography and maintained along with and as part of the disconnect switch and, therefore, meets the definition of an active component as discussed in the Statement Of Considerations (SOC) that accompanied the License Renewal Rule.

At PBNP, the switchyard bus is associated with the in-scope portion of the Offsite Power System interconnections between the Unit 1 circuit switcher and the high-voltage station auxiliary transformer and between the Unit 2 circuit switcher and the high-voltage station auxiliary transformer. Outside the scope of license renewal, the switchyard bus also connects these circuit switchers to the tie breakers between the switchyard components and the incoming lines and between the five segments of the main interconnecting switchyard bus sections. Since this is three-phase power, there are three parallel switchyard bus segments in each circuit path that are constructed of the same materials and components.

Transmission Conductors

Transmission conductors are uninsulated, stranded electrical cables used in switchyards, switching stations and transmission lines to connect two or more elements of an electrical power circuit such as active disconnect (gang) switches, power circuit breakers and transformers and passive switchyard bus. Passive high-voltage strain or suspension insulators support transmission conductors. High-voltage strain and suspension insulators and switchyard bus are reviewed elsewhere in this document.

Transmission conductors are within the scope of license renewal for the Point Beach Nuclear Plant. The only use of a transmission type conductor is within the extended SBO scope for the short connections from each unit's high-voltage station auxiliary transformer surge arrestors to sections of 4" aluminum switchyard bus. These conductors are 2156 MCM aluminum jumper cables with a steel core (ACSR) in short sections between rigidly supported connecting equipment. The switchyard buses form the principal connections from these transformers to their respective circuit switchers.

The other use (except for transmission lines) of transmission type conductors within the switchyard is for the connections from switchyard bus to the bus tie breakers, located between the five bus sections. The same 2156 MCM ACSR cable is used in these locations. These components and connections are beyond the circuit switchers, which are the bounding devices in the switchyard for recovery of offsite power due to SBO.

The transmission conductor connections to active disconnect switches, power circuit breakers and transformers are inspected using thermography and maintained along with and as part of the disconnect switch, power circuit breaker or transformer and, therefore, meet the definition of an active component as discussed in the Statement Of Considerations (SOC) that accompanied the License Renewal Rule.

High-Voltage Insulators

According to IEEE 100-1984 an insulator is an insulating material in a form designed to (a) support a conductor physically and (b) separate the conductor electrically from another conductor or object. The high-voltage insulators evaluated for license renewal are those used to support and insulate high-voltage electrical components in the switchyard, transmission lines such as transmission conductors, and switchyard bus.

There are two basic types of high-voltage insulators: station post insulators and strain or suspension insulators. Station post insulators are large and rigid. They are used to support stationary switchyard equipment such as bus and disconnect switches. Multiple station post insulators can be fastened together (end to end) to increase the electrical separation between the electrical component and the supporting structure. Strain and suspension insulators are smaller than station post insulators and are constructed in a way that allows them to be strung together; different string lengths for different separation requirements. They are used in applications where movement of the supported conductor is expected and allowed. Strain and suspension insulators are the same type of insulators; the difference in name is due to their application. Strain insulators are used to maintain tensional support for a transmission conductor between transmission towers or other supporting structures. Suspension insulators normally hang in a vertical position, maintain the conductor spacing from other objects and are normally under only tension due to the gravity load of the supported conductor and the other insulators in the string.

The review of high-voltage insulators includes only the insulator. High-voltage insulators serve as an intermediate support between a supporting structure, such as a support pedestal or transmission tower, and the switchyard bus or transmission conductor, respectively. Support pedestals are reviewed in the structural supports aging management review. Switchyard bus and associated fastening hardware are reviewed elsewhere in this document. Transmission towers, transmission conductors (beyond the identified SBO circuit switcher interface), and associated fastening hardware are not within the scope of license renewal for the Point Beach Nuclear Plant.

At PBNP, high-voltage insulators are associated with the in-scope portion of the Offsite Power System as station post insulators providing support for the switchyard bus connecting the unit high-voltage station auxiliary transformers and the circuit switchers and support for the circuit switchers themselves. While not within the scope of LR, they are also used throughout the balance of the switchyard as station post insulators and as strain and suspension insulators for transmission lines supported from the transmission towers.

Uninsulated Ground Conductors

Uninsulated ground conductors are electrical conductors (e.g., copper cable, copper bar) that are uninsulated (bare) and are used to make ground connections for electrical equipment. Uninsulated ground conductors are connected to electrical equipment housings and electrical enclosures as well as metal structural features such as cable tray equipment and building structural steel. Uninsulated ground conductors are connected by compression or fusion (soldered or welded) connections to interfacing equipment. Compression and fusion connections involve various types of metals and other inorganic materials that have no aging effects that would result in loss of intended function.

Uninsulated ground conductors enhance the capability of the electrical system to withstand electrical system disturbances (e.g., electrical faults, lightning surges) for equipment and personnel protection. Uninsulated ground conductors are always isolated or insulated from the electrical operating circuits and are not required for those circuits or equipment to perform their intended functions. Therefore, uninsulated ground conductors are not within the scope of license renewal for the Point Beach Nuclear Plant.

Panels and Junction Boxes

The panels and junction boxes commodity includes control boards, electrical panels, switchgear, cabinets, junction boxes, and other electrical enclosures. These electrical enclosures are found in all electrical power systems and instrumentation and control systems. Panel mounted drip and spray shields are included in the consideration of panels and junction boxes. This commodity is considered as a part of the Component Supports Commodity Group (CSUP)

CSUP provides the aging management review of all structural support components, including the fasteners and anchorages, for system piping, ventilation ducting, enclosures that can house electrical components (panels and junction boxes commodity), raceways (tray and conduit), and other equipment within the scope of license renewal.

2.5.2 120 VAC Vital Instrument Power System

System Description

The 120 VAC Vital Instrument Power System is supplied from the 125 VDC Power System and the 480 VAC Power System. The 120 VAC Vital Instrument System provides power to both safety and non-safety related systems and is used throughout the plant. During normal, abnormal, or emergency conditions the 120 VAC Vital Instrument Power

System provides continuous power of adequate voltage and quality to connected safety related loads. During a design basis accident combined with a loss of offsite power and a single failure, the 120 VAC Vital Instrument Power System provides continuous power to the Engineering Safety Feature (ESF) Actuation System to ensure a spurious Safety Injection actuation does not occur in the non-accident unit. During a Station Blackout (SBO) or plant fires, the 120 VAC Vital Instrument Power System supplies continuous power to those instrument loads necessary to achieve and maintain safe reactor shutdown.

The system consists of sixteen buses, divided among four instrument channels. Each of the four channels (red, white, blue, and yellow) are allocated four buses. The distribution buses are further subdivided into two bus groups, one group serving Unit 1 and the other serving Unit 2. Each channel is powered by three inverters that convert power from 125 VDC to 120 VAC. One inverter is dedicated to the Unit 1 bus group and a second inverter is dedicated to the Unit 2 bus group. The third inverter is an alternate, and can swing between the Unit 1 and Unit 2 buses using manual make-before-break transfer switches. The three inverters powering any one instrument channel share a common supply from one of the main 125 VDC buses. Although normally powered from an inverter supply, each instrument channel can also be powered from a backup power source. The backup power source is from two non-safety related instrument buses which are supplied from a 480 VAC bus via a 480/120 VAC regulating transformer which is outside the scope of license renewal.

The output of each inverter is connected to a static transfer switch that will automatically transfer the associated instrument buses to the backup power source in the event of an inverter failure, with little or no power interruption. Signals causing the transfer of the static switches include high voltage (white and yellow channels only), low voltage, current overload, and inverter failure signal (anticipatory to loss of voltage). The backup source is designed to maintain power to affected buses only until they can be manually transferred back to an operable inverter. The backup source is designed to supply the Unit 1 and Unit 2 loads of one instrument bus channel. It will therefore maintain power to the affected instrument bus channel in the case of a main DC bus failure. Electrical interlocks are in place to prevent static switches from more than one instrument bus channel from transferring to the backup source at the same time.

The 120 VAC Vital Instrument Power System provides power to various instrument racks for the Reactor Protection System (RPS), the Engineered Safety Feature Actuation System (ESFAS), the Nuclear Steam Supply System (NSSS) Controls, and other miscellaneous instrumentation and control systems. The White and Yellow instrument channels supply two isolation transformers which supply eight Radiation Monitoring (RM) System's non-safety related instrument panels in addition to other non-safety related loads. The isolation transformers are used to prevent remote faults from non-safety related components from feeding back to the protection buses.

In addition to the four 120 VAC instrument channels there are two (per unit) non-safety related portions of the 120 VAC Instrument Power System. These four additional instrument buses supply power to non-protection, non-redundant instruments. Each bus is energized from a single 480/120 VAC transformer with no alternate sources of power from the 480 VAV Power System. These buses reduce the required load on the static inverters supplying the protection channels.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the 120 VAC Vital Instrument Power System are non-safety related but their failure could affect the capability of another system to perform its safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Anticipated Transients Without Scram, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the 120 VAC Vital Instrument Power System containing components subject to an AMR include the equipment necessary to achieve and maintain safe reactor shutdown.

The following electrical systems interface with the 120 VAC Vital Instrument Power System:

125 VDC Power	Plant Communications
Miscellaneous AC Power and Lighting	480 VAC Power
Control Rod Drive and Indication and Nuclear Process Instrumentation	Radiation Monitoring

System Function Listing

A comprehensive listing of functions associated with the 120 VAC Vital Instrument Power System, or specific components contained in the system, is provided in the summary below.

Code Q	Cri 1	Cri 2	Cri 3				
PROVIDE ELECTRICAL POWER TO SAFETY CLASS 1, 2, 3 COMPONENTS			FP	EQ	PTS	AT	SB
	X						

Comment: During normal, abnormal, or emergency conditions the 120 VAC Vital Instrument Power System provides continuous power of adequate voltage and quality to connected safety related loads.

Code S	Cri 1	Cri 2	Cri 3				
SPECIAL CAPABILITY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: Provides power for Reg.Guide 1.97, Type B, C, D, and E variables and provides for indication of Reg. Guide 1.97, Type D, Category 2 Variables, not in LR scope

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: The 120 VAC Vital Instrument Power System provides power to non-safety related systems.

Code Y	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 2 - NON-SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION			FP	EQ	PTS	AT	SB
		X					

Comment: Electrical and electronic circuit elements whose failure could prevent an AQ component from performing its required function, but which performs no QA-scope function itself. These components act as isolation points from AQ to non-AQ loads.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The 120 VAC Vital Instrument Power System provides power to process monitoring systems.

During plant fires the vital 120 VAC Instrument Power System supplies continuous power to those instrument loads necessary to achieve and maintain safe reactor shutdown.

Code Z4 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ANTICIPATED TRANSIENTS WITHOUT SCRAM (10 CFR 50.62)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
						X	

Comment: Each unit’s AMSAC is powered from a 120 VAC Vital Power System instrument bus, which can be supplied with power from diesel generators via 4160 VAC and 480 VAC safety related buses.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The 120 VAC Vital Instrument Power System provides power to process monitoring systems.

During a Station Blackout (SBO) the 120 VAC Vital Instrument Power System supplies continuous power, from inverters off of the 125 VDC Power System, to those instrument loads necessary to achieve and maintain safe reactor shutdown.

FSAR Reference

Additional 120 VAC Vital Instrument Power System details are provided in Section 8.6 and Section 7.4.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the 120 VAC Vital Instrument Power System are listed below:

Common
LR-ELECTRICAL-E1

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group’s intended function(s).

2.5.3 125 VDC Power System

System Description

The 125 VDC Power System provides a reliable source of power for safety and non-safety related loads of both PBNP units. The system includes six separate, independent DC distribution buses, each capable of being connected to a common “swing” bus. Four of the six buses and the swing buses are safety related and shared between the units. The other two buses are non-safety related and each is dedicated to a single unit. Each DC bus is powered by at least one AC-to-DC battery charger (eight total), backed up by a station battery (seven total). The swing buses have two chargers and one battery that are sized to carry any one of the six independent buses.

During normal operation each safety related DC bus shall supply uninterruptible DC power of adequate voltage and quality to support systems that monitor for abnormal/accident conditions and initiate protective actions. During abnormal or emergency conditions, with or without a concurrent loss of offsite power, each safety related DC bus shall supply uninterruptible DC power of adequate voltage and quality to safety related loads for accident mitigation. During station blackout, the system shall continuously supply power to those loads required to achieve and maintain safe reactor shutdown during the blackout period. During normal plant operation, the system shall continuously supply power of adequate voltage and quality to connected loads.

The safety related 125 VDC Power System consists of four main distribution buses. Two of these buses supply power for control, emergency lighting, and the red and blue 120 VAC Vital Instrument Power System inverters. The other two main DC distribution buses supply power for control and the white and yellow 120 VAC Vital Instrument Power System inverters.

Each of the four main distribution buses is powered by a battery charger and is backed up by a station battery. The function of the battery chargers is to supply their respective DC loads, while maintaining the batteries at full charge. All of the battery chargers are powered from the 480 VAC Power System. The safety related battery chargers have been sized to recharge any of their respective partially discharged safety related batteries within 24 hours while carrying normal loads. In addition to the four 125V safety related main distribution buses, there exist two safety related swing DC distribution buses which permit the connection of a swing battery and/or a swing charger to one of the four main distribution buses. Two swing battery chargers are available through one of the swing DC distribution buses. The swing battery is capable of being aligned to any one of the four main distribution buses to take the place of the normal battery. Kirk key interlocks exist on swing DC distribution buses which prevent the paralleling of redundant DC buses. One swing bus can also be connected with two non-safety related (NSR) buses which are connected to two NSR batteries and chargers. The NSR buses and ancillary equipment are dedicated to a specific unit, and supply power to non-safety related loads.

Emergency power supply for vital instruments, control power, and for some DC emergency lighting of both units is supplied from the four 125 VDC station batteries which are common to both units. Additional emergency lighting, provided in “safe shutdown” areas and access routes to and from these areas, are powered by their own attached battery power supplies.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the 125 VDC Power System are non-safety related but their failure could affect the capability of another system to perform its safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the 125 VDC Power System containing components subject to an AMR include the equipment necessary to provide 125 VDC power to achieve and maintain safe reactor shutdown.

The following Electrical Systems interface with the 125 VDC Power System:

Emergency Power	120 VAC Vital Instrument Power System
480 VAC Power	Miscellaneous AC Power and Lighting
4160 VAC Power	Offsite Power
13.8K VAC Power	

System Function Listing

A comprehensive listing of functions associated with the 125 VDC Power System, or specific components contained in the system, is provided in the summary below.

Code Q	Cri 1	Cri 2	Cri 3				
PROVIDE ELECTRICAL POWER TO SAFETY CLASS 1, 2, 3 COMPONENTS			FP	EQ	PTS	AT	SB
	X						

Comment: The safety related 125 VDC Power System consists of four main distribution buses. Two of these buses supply power for control, emergency lighting, and the red and blue 120 VAC Vital Instrument Power System inverters. The other two main DC distribution buses supply power for control and the white and yellow 120 VAC Vital Instrument Power System inverters.

Code S	Cri 1	Cri 2	Cri 3				
SPECIAL CAPABILITY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: Provides for indication of Reg. Guide 1.97, Type D, Category 2 Variables, not in LR scope.

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: The 125 VDC Power System provides power to non-safety related loads.

Code Y	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION			FP	EQ	PTS	AT	SB
		X					

Comment: Electrical and electronic circuit elements whose failure could prevent an AQ component from performing its required function, but which performs no QA-scope function itself. These components act as isolation points from AQ to non-AQ loads.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The 125 VDC Power System provides power to the 120 VAC Vital Instrument Power System for those instrument loads necessary to achieve and maintain safe shutdown.

The safety related 125 VDC Power System supplies power for emergency lighting and control power for Appendix R switchgear.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The 125 VDC Power System maintains functionality of electrical components as addressed by the Environmental Qualification Program.

The 125 VDC Power System contains electrical equipment that is environmentally qualified.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The 125 VDC Power System provides power to the 120 VAC Vital Instrument Power System to support process monitoring systems.

During Station Blackout, the system continuously supplies power to those loads required to achieve and maintain safe reactor shutdown during the blackout period. In addition, the system supplies control power needed to restore offsite power following recovery from an SBO event.

FSAR Reference

Additional 125 VDC Power System details are provided in Section 8.7 of the FSAR.

License Renewal Drawings

The license renewal drawings for the 120 VAC Vital Instrument Power System are listed below:

Common
LR-ELECTRICAL-E1

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group's intended function(s).

2.5.4 4160 VAC Power System

System Description

The 4160 VAC Power System consists of a unit auxiliary transformer (19K/4160 VAC), a low voltage station auxiliary transformer (13.8K/4160 VAC), four non-safeguard buses and two safeguard buses per unit. During unit operation, two of the non-safeguard buses are supplied by independent secondary windings of the unit auxiliary transformer. The primary side of the unit auxiliary transformer is directly connected to the leads of the main generator, the main source of 4160 VAC auxiliary power during unit operation. The other two non-safeguard buses are supplied by the independent secondary windings of the low voltage station auxiliary transformer, the primary side of which is supplied by the 13.8K VAC Power System. The safeguard buses are supplied by the two low voltage supplied non-safeguard buses via manually closed tie breakers. The safeguard buses supply all of the safety related loads via 4160 VAC and 480 VAC transformers. The two 4160 VAC safeguard buses each serve one of the two 4160/480 VAC station service transformers for the unit's 480 VAC safeguards equipment and one of the two safety injection pumps. Thus, no transfer is required for the safeguards equipment in the event of a turbine generator trip.

In addition to being served by the low voltage station auxiliary transformer via two 4160 VAC non-safeguard buses, the 4160 VAC safeguard buses are directly served by the four (4) emergency diesel generators (DGs). These DGs can provide power to a specific train or unit or to individual buses, depending upon availability and alignment. Load shedding and load sequencing is provided to ensure that there is sufficient DG capacity to supply all safety related loads when required during an event.

All normal operating non-safeguard 4160 VAC auxiliaries are split between the two non-safeguard buses supplied by the unit auxiliary transformer. In addition, these buses each serve one 4160/480 VAC station service transformer. Each of these buses can be tied to one of the other two non-safeguard buses via bus tie breakers. The normal at-power alignment is with the tie breakers open. If a plant trip occurs, the supply breakers from the unit auxiliary transformer will trip, and the tie breakers will fast transfer close, provided voltage is matched and frequency is synchronized. This line-up is also used for startups and shutdowns; thus, the two non-safeguard buses powered from the low voltage station auxiliary transformer will provide all 4160 VAC power during startup, shutdown, and after a reactor trip. Manually closed tie breakers are supplied between the two unit's buses supplied by the low voltage station auxiliary transformers which may be operated if either unit’s low voltage transformer is removed from service.

The 4160 VAC Power System provides a reliable source of power to the safety related loads during all normal and emergency plant operating conditions. During station blackout conditions the 4160 VAC Power System will supply power to those loads required to achieve and maintain safe reactor shutdown. The 4160 VAC Power System has sufficient independence from offsite sources to be rapidly isolated to protect the safeguard buses in the event of a design basis accident. The 4160 VAC Power System is designed with redundant power sources to ensure a single failure will not prevent a safety related component from performing its intended function.

The auxiliary electrical sub-system is designed to provide a simple arrangement of buses requiring the minimum of switching to restore power to a bus in the event that the normal supply to that bus is lost. The 4160 VAC Power System has a series of relays that automatically initiate features designed to provide protection to the safety related buses and loads. The 4160 VAC relaying scheme is designed to detect abnormal conditions of voltage/frequency and effect compensatory actions (i.e. tripping/closing tie breakers, tripping feeder breakers, starting the emergency diesel generators, etc.). The 4160 VAC relays receives actuation signals from: Safety Injection (SI), Containment Pressure Condensate Isolation (CPCI), Steam Generator Feedpump Trips, Turbine Trip Logic Signal, and Heater Drain Tank low level. Additionally, the 4160 VAC Power System provides input to the Safety Injection (SI) reset logic, reactor trip logic, and Diesel Generator (DG) starting logic. Bus supply breakers from offsite power are tripped on loss of bus voltage and they must be manually reclosed upon restoration of offsite power.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection, Anticipated Transients Without Scram, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the 4160 VAC Power System containing components subject to an AMR includes the equipment necessary to provide 4160 VAC power to those loads necessary to achieve and maintain safe reactor shutdown.

The following electrical systems interface with the 4160 VAC Power System:

Emergency Power	480 VAC Power
125 VDC Power	13.8K VAC Power
Offsite Power	

System Function Listing

A comprehensive listing of functions associated with the 4160 VAC Power System, or specific components contained in the system, is provided in the summary below.

Code D	Cri 1	Cri 2	Cri 3				
SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION			FP	EQ	PTS	AT	SB
	X						

Comment: The 4160 VAC relays receive actuation signals from: Safety Injection (SI), Containment Pressure Condensate Isolation (CPCI), Steam Generator Feedpump Trips, Turbine Trip Logic Signal, and Heater Drain Tank low level. Additionally, the 4160 VAC Power System provides input to the Safety Injection (SI) reset logic, reactor trip logic, and Diesel Generator (DG) starting logic.

Code Q	Cri 1	Cri 2	Cri 3				
PROVIDE ELECTRICAL POWER TO SAFETY CLASS 1, 2, 3 COMPONENTS			FP	EQ	PTS	AT	SB
	X						

Comment: The 4160 VAC Power System provides a reliable source of power to the safety related loads during all normal and emergency plant operating conditions.

Code S	Cri 1	Cri 2	Cri 3				
SPECIAL CAPABILITY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: Provides for indication of Reg. Guide 1.97, Type D, Category 2 Variables, not in LR scope.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The majority of electrical loads, used for both safety and non-safety related applications, are powered by the 480 VAC Power System. The various sources, used to supply the 480 VAC Power System, are rated at different voltages and the 4160 VAV Power System provides the primary means to interconnect the onsite and offsite power sources and distribute the power to the 480 VAC Power System.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The 4160 VAC Power System provides power to the 480 VAC Power System to support safe shutdown components.

The majority of electrical loads, used for both safety and non-safety related applications, are powered by the 480 VAC Power System. The various sources, used to supply the 480 VAC Power System, are rated at different voltages and the 4160 VAV Power System provides the primary means to interconnect the onsite and offsite power sources and distribute the power to the 480 VAC Power System.

Code Z4 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ANTICIPATED TRANSIENTS WITHOUT SCRAM (10 CFR 50.62)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
						X	

Comment: AMSAC monitors the availability of main feedwater by way of the 4160 VAC breaker position for the main feedwater pumps.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The 4160 VAC Power System shall be capable of providing power to 480 VAC Power System to support safe shutdown components.

FSAR Reference

Additional 4160 VAC Power System details are provided in Section 8.4 and Section 7.4.1 of the FSAR.

License Renewal Drawings

The license renewal drawings for the 4160 VAC Power System are listed below:

Common
LR-ELECTRICAL-E1

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group's intended function(s).

2.5.5 480 VAC Power System

Description

The majority of the electrical loads used for normal and emergency plant operations are powered from the 480 VAC Power System (CHAMPS System: 480V). The 480 VAC Power System is supplied by the 4160 VAC Power System through the 4160/480 VAC station service transformers and diesel generator building transformers. The 480 VAC Power System is divided into four main buses per unit, and the safeguards equipment is connected to two of these per unit. The equipment is arranged so that no single contingency can inactivate enough safeguards equipment to jeopardize plant safety. The safeguards equipment connected to the two 480 VAC buses for each unit are powered via a normal connection path from the Offsite Power System (345K VAC) through the 4160 VAC Power System such that no transfer is required in the event of a turbine generator trip.

A pair of 480 VAC alternate shutdown buses can be powered from the 13.8K VAC Power System by a Gas Turbine (GT) through a 13.8K/480 VAC transformer. Safe shutdown equipment is aligned to these buses by alternate transfer switches located at remote shutdown stations throughout the plant. The system provides the means to reliably distribute 480 VAC power to those loads required during normal and emergency plant conditions, including those loads required to mitigate the consequences of all postulated accidents.

Portions of the 480 VAC Power System are also required to provide power to essential safe shutdown equipment during Station Blackout (SBO). Undervoltage devices are provided for the loads on the safeguards buses. They control load shedding and determine when the load sequencing timers can begin timing after a Diesel Generator (DG) start.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the 480 VAC Power System containing components subject to an AMR include the equipment necessary to provide 480 VAC power to those loads necessary to achieve and maintain safe reactor shutdown.

The following electrical systems interface with the 480 VAC Power System:

Emergency Power	4160 VAC Power
120 VAC Vital Instrument Power	13.8K VAC Power
Miscellaneous AC Power and Lighting	125 VDC Power

System Function Listing

A comprehensive listing of functions associated with the 480 VAC Power System, or specific components contained in the system, is provided in the summary below.

Code D SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Undervoltage devices are provided for the loads on the safeguards buses that control load shedding and determines when the load sequencing timers can begin timing after a Diesel Generator (DG) start.

Code Q PROVIDE ELECTRICAL POWER TO SAFETY CLASS 1, 2, 3 COMPONENTS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Safeguards equipment is connected to two 480 VAC buses per unit.

Code S SPECIAL CAPABILITY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Provides for indication of Reg. Guide 1.97, Type D, Category 2 Variables, not in LR scope.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The majority of electrical loads, used for both safety and non-safety related applications, are powered by the 480 VAC Power System.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The 480 VAC Power System provides power to safe shutdown components.

A pair of 480 VAC alternate shutdown buses can be powered from the 13.8K VAC Power System by a Gas Turbine (GT) through a 13.8K/480 VAC transformer. Safe shutdown equipment is aligned to these buses by alternate transfer switches located at remote shutdown stations throughout the plant.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The 480 VAC Power System maintains functionality of electrical components as addressed by the Environmental Qualification Program.

The 480 VAC Power System contains electrical equipment that is environmentally qualified.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: Portions of the 480 VAC Power System provide power to essential safe shutdown equipment during Station Blackout (SBO).

FSAR Reference

Additional 480 VAC Power System details are provided in Section 8.5 of the FSAR.

License Renewal Drawings

The license renewal drawings for the 480 VAC Power System are listed below:

Common
LR-ELECTRICAL-E1

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group's intended function(s).

2.5.6 Control Rod Drive and Indication System and Nuclear Process Instrumentation

Description

The Control Rod Drive and Indication System and Nuclear Process Instrumentation is a combination of sub-systems which provide reactor control and monitoring.

The rod control sub-system provides automatic control of the control rods during power operation of the reactor. The rod control sub-system uses input signals from different plant parameters, including neutron flux, reactor coolant temperature, and plant turbine load to maintain an average reactor coolant temperature.

The control rods or rod cluster control assemblies (RCCAs), provided to control the reactivity of the core, each consist of a group of individual absorber rods fastened at the top end to a common hub or spider assembly. The magnetic latch control rod drive mechanisms (CRDMs) are used for withdrawal and insertion of the RCCAs into the reactor core and to provide sufficient holding power for stationary support. Fast total insertion (reactor trip) is obtained by simply removing the electrical power, allowing the rods to fall by gravity. The complete CRDM consists of the drive shaft assembly, internal latch assembly, the pressure vessel (considered for License Renewal as part of the Reactor Coolant System), the operating magnetic coil stack, and the position indicator coil stack.

The rod speed and direction control sub-system maintains a program average reactor coolant temperature by providing speed and direction signals to the rod control sub-system logic cabinet. Speed and direction command signals produced by this sub-system are supplied to the rod control sub-system operating in the automatic mode. These signals cause the RCCAs to move in banks in the necessary direction, and at sufficient speed to maintain average temperature at or near the reference temperature.

RCCA position is monitored and indicated by two independent sub-systems. One sub-system provides rod group position via mechanical step counter indication (one per group) on the control board while the second sub-system utilizes signals from the individual rod position indicator coil stacks that span the normal length of rod travel and detect drive rod position. The rod insertion limit alarm sub-system provides the operator with alarm information to aid in maintaining the control rods at the most desirable location in the core with respect to maintaining adequate shutdown margin.

The ex-core nuclear instrumentation consists of eight neutron flux monitoring channels divided into three overlapping ranges: two source range channels, two intermediate range channels, and four power range channels. The three ranges combine to provide a continuous, overlapping measurement of approximately eleven decades of reactor power, from a completely shutdown condition to 120% of full power. The power range channels are capable of recording overpower excursions up to 200% of full power.

The normal source, intermediate, and power range channels provide control room indication and recording of reactor neutron flux during core loading, shutdown, startup, and power operation. Reactor trip and rod stop control and alarm signals are provided by this system for safe plant operation. Control and permissive signals are transmitted to the reactor control sub-systems and Reactor Protection System for automatic plant control.

A Gamma-Metrics neutron flux monitor is used as an environmentally qualified (EQ) backup indication to the normal source, intermediate, and power range channels primarily for the purpose of Post-Accident Monitoring. This monitoring sub-system employs a single channel in each unit that is designed to measure neutron flux in a harsh environment from source range level to 200% of rated power. This EQ detector is also used for back-up Source Range indication only for refueling activity.

The in-core instrumentation sub-system consists of thermocouples, positioned to measure fuel assembly coolant outlet temperature at preselected locations, and flux thimbles, which run the length of selected fuel assemblies through which moveable neutron detectors are passed to measure the neutron flux distribution within the reactor core. The thimbles are part of the RCS boundary and thermocouples, which are EQ components, are considered part of the non-Class 1 reactor coolant system components.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). Since some SSCs in the Control Rod Drive and Indication System and Nuclear Process Instrumentation are non-safety related but their failure could affect the capability of another system to perform its safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Control Rod Drive and Indication System and Nuclear Process Instrumentation containing components subject to an AMR includes the equipment necessary to monitor neutron flux and generate trip signals to achieve and maintain safe reactor shutdown.

The following systems interface with the Control Rod Drive and Indication System and Nuclear Process Instrumentation:

480 VAC Power	120 VAC Vital Instrument Power System
Reactor Protection	

System Function Listing

A comprehensive listing of functions associated with the Control Rod Drive and Indication System and Nuclear Process Instrumentation, or specific components contained in the system, is provided in the summary below.

Code D SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Reactor trips supported by the ex-core nuclear instrumentation include source range high level, intermediate range high level, power range high level (low setting), and power range high level (high setting). In addition, the power range channels provide flux difference signals to the overtemperature delta T trip.

Code E PROVIDE REACTOR COOLANT PRESSURE BOUNDARY	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: Each control rod drive assembly is designed as a hermetically sealed unit to prevent leakage of reactor coolant water. All pressure-containing components are designed to meet the requirements of the ASME Code, Section III, 1965 Edition, Class A Nuclear Vessels.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The in-core nuclear instrumentation provides: information on neutron flux distribution and fuel assembly outlet temperature at selected locations in the core; information used to calculate fuel burnup distribution; detection or verification of rods out of position, and information used to calibrate the ex-core NIs for axial offset.

The ex-core nuclear instrumentation provides: continuous monitoring of the core neutron flux outside the reactor vessel with three ranges (source, intermediate, and power) of instrumentation, and alarms and control signals during operation in all three ranges of instrumentation.

The Gamma-Metrics provides reliability monitoring of neutron flux with a wide range instrument.

The rod speed and direction control sub-system provides automatic position control of RCCAs in banks to maintain a program average reactor coolant temperature.

Provide the operator with rod insertion limit alarm information.

The function of the Control Rod Drive System is to move the 33 full length RCCAs to control the fission rate in the reactor, in response to command signals from either the reactor operator or the reactor control sub-system. Also, the system provides RCCA position indication by two independent systems.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: Nuclear instrumentation meters and recorders and control rod controls and position indicators mounted in the main control boards are required to maintain structural integrity and mounting adequacy in a seismic event (SSE). No post-accident functionality is required.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The ex-core nuclear instrumentation monitors process parameters for source range levels in the reactor.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The nuclear instrumentation Gamma-Metrics wide-range neutron flux monitor sub-system maintains functionality of electrical components as addressed by the Environmental Qualification Program.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The post-accident monitoring function of the nuclear process instruments is relied upon to provide indication to control room operators regarding plant parameters necessary to achieve and maintain safe shutdown during a SBO.

FSAR Reference

Additional Control Rod Drive and Indication System and Nuclear Process Instrumentation details are provided in Section 3.4, Section 7.7.1, Section 7.6.1, and Section 7.6.3 of the FSAR.

License Renewal Drawings

None.

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group’s intended function(s).

2.5.7 Miscellaneous AC Power and Lighting System

Description

The Miscellaneous AC Power and Lighting System is a combination of various plant power systems that provide power to miscellaneous loads throughout the interior and exterior of the plant site. The Miscellaneous AC Power and Lighting System converts higher voltage power via transformers to 120 VAC, and distributes it as required to small station equipment.

The Miscellaneous AC Power and Lighting System station lighting sub-system supplies power for both normal and emergency lighting. The system consists of eight major transformers that supply power to general plant areas, each with an associated distribution panel and a number of lighting panels. Two of these circuits are termed emergency lighting and are powered from safeguards buses. There are over twenty-eight (28) other transformers, each with its own panel, that are more localized in their service area such as individual rooms, separate buildings or specialized loads.

Generally, most of the various supply transformers are three phase 480/208-120 VAC transformers. A few transformers are single phase 480/240-120 VAC. The three phase lighting panels are supplied by three phase 208 VAC, and the single phase 120 VAC loads are apportioned approximately equally across the three phases of the supply transformers. The single-phase cabinets contain two energized bus bars across which 240 VAC can be obtained.

The station lighting sub-system consists of various fixtures that are distributed and spaced to provide adequate illumination to the most inaccessible areas of the plant and the areas immediately outside of plant buildings. A portion of these fixtures is energized from the emergency lighting panels. These emergency fixtures are located such that in the event of a loss of normal AC power most areas of the plant will receive some lighting, especially the various doorway and stairwell areas, to allow safe passage. In addition, a system of battery powered lights is installed in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto. The batteries are lead acid, 6V, 100 amp, 20 hour rated batteries, and each is supplied with an eight amp minimum high rate charger. As a final back up to emergency lighting, fifteen portable, battery operated, high intensity lanterns are strategically located throughout the plant for fire brigade use.

Plant exterior lighting is powered from two 480 VAC buses via step-up transformers that supply 2400 VAC power through underground feeders. Step-down transformers reduce the 2400 VAC to 240 VAC for distribution to various lighting fixtures via four distribution panels.

Parking lot and station roadway lighting is provided from a 480/208-120 VAC step-down transformer. The south meteorological tower is powered from a 4160 VAC bus via a 4160/208 VAC step-down transformer, and the north meteorological tower is powered from offsite by the Wisconsin Public Service feeder via a 345K/4160 VAC step-down transformer and a 4160/208 VAC step-down transformer.

The switchyard control house and yard lighting is powered from the 480 VAC Power System via a 480/208-120 VAC transformer. The 120 VAC power is used for lighting, telemetering and recording, and battery chargers for yard control power. The 208 VAC power is also used for yard battery chargers.

In addition to lighting and wall receptacles, the Miscellaneous AC Power and Lighting System also energizes such equipment as selected controls, small motors for pumps, fans or compressors, area heaters, public address and telephone equipment, office equipment, water coolers, boric acid heat tracing, facade freeze protection, and cathodic protection equipment. The system provides power for the bus duct heaters for each unit’s high-voltage and low-voltage station auxiliary transformers, which are part of the 13.8K VAC and 4160 VAC Power Systems, respectively.

Each unit’s containment structure is housed in an unheated enclosure, the facade, which provides protection from the weather. Each unit’s refueling water storage tank (RWST) and its associated piping and instrumentation is also located in the facade-enclosed area. The Miscellaneous AC Power and Lighting System provides power to the freeze protection for the RWST piping and instrumentation enclosures, as well as providing power to heat tracing for other instrumentation lines which run through the facade area. Similarly, power is supplied to heat tracing inside the plant buildings where piping and tanks may contain higher concentrations of boric acid.

Miscellaneous AC Power and Lighting System provides power to an impressed-current cathodic protection system, which utilizes close coupled anodes to protect the containment pilings and interconnected containment liner, reinforcing bars, and tendon steel casings. No credit is taken for the cathodic protection system when these structural components are evaluated for the extended period of operation.

Since SSCs in the Miscellaneous AC Power and Lighting System are non-safety related but their failure could affect the capability of another system to perform its safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Miscellaneous AC Power and Lighting System containing components subject to an AMR include the equipment necessary to provide emergency lighting and freeze protection.

The following electrical systems interface with the Miscellaneous AC Power and Lighting System:

13.8K VAC Power	4160 VAC Power
480 VAC Power	Offsite Power

System Function Listing

A comprehensive listing of functions associated with the Miscellaneous AC Power and Lighting System, or specific components contained in the system, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The system provides power for various non-safety related loads and illumination throughout the plant buildings and exterior lighting in the protected area and switchyard.

Code Y LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
		X					

Comment: Facade Freeze Protection sub-system provides freeze protection for portions of safety related systems, such as the refueling water storage tank, that are inside the containment facade for each unit.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Emergency Lighting sub-system provides emergency lighting with 8 hour battery packs for operation of safe shutdown equipment and access and egress to the panels and areas.

Code Z5	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - SSC'S 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)			FP	EQ	PTS	AT	SB
							X

Comment: The switchyard control house and yard lighting is powered from the 480 VAC Power System via a 480/208-120 VAC transformer. The 120 VAC power is used for lighting, telemetering and recording, and battery chargers for yard control power, which supports restoration of offsite power following a SBO event. The 208 VAC power is also used for yard battery chargers to support switchyard operations.

FSAR Reference

None.

License Renewal Drawings

None.

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group’s intended function(s).

2.5.8 Offsite Power System

Description

Offsite Power consists of the 345K VAC and 19K VAC sub-systems at the Point Beach Nuclear Plant. The main transmission lines of the American Transmission Company, LLC (ATC LLC), operate at 345K VAC. The Point Beach Nuclear Plant has two main generators that produce electrical power at 19K VAC. The 19K VAC sub-system distributes the energy developed by each unit’s main generator to the main transformers and each unit’s auxiliary transformer. The output of the main generator is stepped up to 345K VAC by the main transformers, and stepped down to 4160 VAC by the unit’s auxiliary transformers. The main generator output circuit breaker is on the 345K VAC side of the main transformers and is used to connect to the ATC LLC 345K VAC switchyard and grid. Likewise, the main generator auxiliary output circuit breaker is on the 4160 VAC side of the unit’s auxiliary transformers and is used to connect to the unit’s 4160 VAC non-safeguards buses.

The 19K VAC sub-system does not perform any safety related function and is classified non-safety related. The 19K VAC sub-system performs the following functions: 1) transmits the power generated by the main output generator to the main and unit auxiliary transformers, 2) provide power to PBNP auxiliaries via the auxiliary transformers during normal plant operations, and 3) provide a means to step up the output voltage of the main generator, from 19K VAC to 345K VAC, for use in the ATC LLC transmission system.

The 345K VAC sub-system does not perform any safety related function and is classified non-safety related. The 345K VAC sub-system performs the following functions: 1) transmits the power generated at PBNP to the ATC LLC 345K VAC switchyard and grid, 2) provides standby power to PBNP auxiliaries during unit(s) startup, shut down, and after reactor trip, and 3) provides a reliable source of normal power to PBNP engineered safeguards equipment.

The Switchyard Electrical Supervisory sub-system of the ATC LLC provides for power, control, and protection of the 345K VAC sub-system equipment, does not perform any safety related function, and is classified non-safety related.

Each unit is equipped with one Westinghouse hydrogen inner-cooled turbine generator. Each generator produces and delivers 19K VAC, 3 phase, 60 Hz. electric power to the main transformer where it is stepped up to 345K VAC for use in the ATC LLC transmission system. The unit’s main transformer output is connected to the PBNP 345K VAC sub-system, which connects to the ATC LLC switchyard. Each generator output also feeds the associated unit auxiliary transformer where the voltage is stepped down to 4160 VAC for use within the station. The generators deliver power to the main and auxiliary transformers through isolated phase buses. The isolated phase bus is a force-cooled metal clad bus that connects the output of the main generator to the main transformer. The Service Water (SW) System provides the cooling for the isolated phase bus through an air-to-water cooler.

The main transformer consists of a bank of three separate transformers, one for each phase. Each transformer is a Class FOA, outdoor, shell form power transformer. The FOA class is cooled by forced oil, which in turn is cooled by forced air. The main transformers are located outside and adjacent to their respective turbine buildings. The main generator output circuit breakers are located in the switchyard on the west side of the site adjacent to the protected area fence. The ATC LLC 345K VAC transmission sub-system consists of four (4) lines connected to the plant switchyard. Each line is carried on a separate line structure in order to minimize the possibility of fault propagation due to lightning or other physical harm. The electrical output of both units is integrated into ATC LLC’s 345K VAC transmission sub-system, which presently has 345K VAC interconnections with Exelon, Excel, and Sault Edison Power Companies. Control power for the generator output breakers is obtained from the switchyard batteries, which are supported by chargers supplied by PBNP's 480 VAC Power System. Plant output is administratively restricted with less than the minimum offsite lines available.

During normal operation of either unit, the auxiliary transformer connected to the isolated phase bus of that unit supplies the power required for station auxiliaries on the 4160 VAC non-safeguards buses. These transformers are part of the 4160 VAC Power System and are located outside in close proximity to their respective main transformers. Following a turbine generator trip, the auxiliaries on the 4160 VAC non-safeguards buses being fed by the unit auxiliary transformer are transferred by a fast bus transfer scheme to the unit's low voltage station auxiliary transformer.

The first source of backup or alternate power, for each unit, is a unit’s low-voltage station auxiliary transformer. The associated unit’s high-voltage station auxiliary transformer normally serves the unit’s low station auxiliary transformer, with an alternate connection to the other unit's high-voltage station auxiliary transformer. The ATC LLC 345K VAC switchyard bus supplies the high-voltage station auxiliary transformers, which are used to supply sufficient power to each unit for start up, shut down, following a reactor trip, and for power associated with safeguard equipment. Transfer from the normal to alternate power alignment is accomplished automatically if a unit's normal high-voltage station auxiliary transformer is tripped and the remaining 13.8K VAC buses are available. One of the four 345K VAC transmission lines can supply all the plant auxiliary power, and a low-voltage station auxiliary transformer can supply all the auxiliary loads for a unit.

The Point Beach operator controls the 345K VAC generator breakers, the 345K VAC circuit switchers, and the 13.8K VAC circuit breakers for the high voltage station auxiliary transformers in the switchyard. All 345K VAC line and bus section breakers are controlled from the Pewaukee System Control Center by supervisory control.

For purposes of Station Blackout (SBO), portions of the 345K VAC equipment are included in the LR scope if they are needed to restore offsite power from the switchyard bus to the high-voltage station auxiliary transformers and the 13.8K VAC Power System. System supervisory, metering, relaying, switches, instrumentation, batteries and chargers, cabinets, controls, and cables are also included if needed to create these connections locally or from the control room.

The description above results in some SSCs in this system being considered in-scope only due to the NRC requirement for restoration of offsite power following a Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Offsite Power System containing components subject to an AMR includes the switchyard equipment necessary to provide 345K VAC power to the high-voltage station auxiliary transformers to restore offsite power following the recovery from an SBO event to meet the NRC LR requirements beyond those in the CLB, which meet the requirements of 10 CFR 50.63.

The following systems interface with the Offsite Power System:

125 VDC Power	480 VAC Power
13.8K VAC Power	

System Function Listing

A comprehensive listing of functions associated with the Offsite Power System, or specific components contained in the system, is provided in the summary below.

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: The Offsite Power System does not perform any safety related functions and is classified non-safety related.

The major function of the 345K VAC sub-system is to provide a path for the power produced by the plant and/or the onsite gas turbine generator to reach the offsite transmission grid connections of the ATC LLC via the switchyard. The 19K VAC sub-system transmits the plant produced power to the 345K VAC sub-system and plant auxiliaries via the unit's auxiliary transformers to the 4160 VAC Power System non-safeguards busses. The switchyard electrical supervisory (SES) sub-system provides for power, control, and protection for the switchyard equipment.

Some plant loads can be supported through connections back into the plant from the 354K VAC system via the 1X03 and 2X03 transformers connected to the 13.8K VAC Power System and the 1X04 and 2X04 transformers connected to the 4160 VAC Power System.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The Offsite Power System components are only in-scope to restore offsite power following the recovery from a Station Blackout (SBO) event, to meet the NRC LR requirements beyond those in the CLB, which meet the requirements of 10 CFR 50.63. They would provide offsite power to essential safe shutdown equipment after recovery from a SBO.

The NRC expanded requirements for LR include restoration of offsite power following an SBO event. Connections from each unit’s high voltage station auxiliary transformers through their circuit switchers to switchyard bus sections provide this connectivity. The switchyard electrical supervisory control cabling, batteries, and equipment in the switchyard building are also brought in-scope.

FSAR Reference

Additional Offsite Power System details are provided in Section 8.1 and Section 8.3 of the FSAR.

License Renewal Drawings

The license renewal drawings for the Offsite Power System are listed below:

<u>Common</u>
LR-ELECTRICAL-E1

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group’s intended function(s).

2.5.9 Reactor Protection System

Description

The Reactor Protection System monitors parameters related to safe operation and automatically trips the reactor to protect the reactor core against fuel rod cladding damage due to Departure from Nucleate Boiling (DNB). It also assists in protecting against Reactor Coolant System (RCS) damage caused by high system pressure by limiting energy input to the system through reactor trip action. The Reactor Protection System reviewed for License Renewal includes the AMSAC sub-system, which stands for

ATWS (Anticipated Transient Without Scram) Mitigating System Actuation Circuitry. The AMSAC design is based on the requirements of 10 CFR 50.62 (c) (1), which requires a system that is independent and diverse from the Reactor Protection System that will automatically initiate the Auxiliary Feedwater System and initiate a turbine trip for an ATWS event.

The RPS limits the range of various core and coolant parameters so that the DNBR is not less than the safety limit value during anticipated operating transients. The parameter ranges were determined by a computer code that mathematically correlated the nuclear and thermal hydraulic properties of the reactor coolant system.

The Reactor Protection System consists of four instrument channels that monitor up to four inputs of various plant parameters, depending on the coincidence logic required for the specific trip. Each protection channel terminates at a channel trip bistable in the analog protection racks. Each channel trip bistable controls two independent and redundant logic relays associated with the two independent and redundant trains (“A” and “B”). The logic relays for each train are combined in a coincidence logic network (e.g., two out of four). The coincidence logic networks terminate at parallel reactor trip relays. The logic and reactor trip relays are located in the Train “A” and “B” logic racks.

Although a single reactor trip relay would be sufficient to trip the reactor, parallel reactor trip relays were installed for power generation reliability. The use of parallel relays prevents an unnecessary reactor trip should a single reactor trip relay fail.

Two independent and redundant reactor trip breakers in series provide power to the control rod drive mechanisms. In addition, two independent and redundant bypass breakers are provided in parallel with the reactor trip breakers to allow for continued reactor operation during testing of the reactor trip breakers.

When the required number of channels (e.g., two-out-of-four) indicate that a plant parameter is outside its acceptable operating limit, their associated channel bistables are tripped. The tripping of the channel bistables results in the tripping of their associated coincidence logic relays for each train, which in turn results in de-energization of the reactor trip relays, which open the reactor trip breakers or bypass breakers for each train by the actuation of the breakers’ undervoltage coil or shunt trip attachment.

Manual reactor trip switches are also installed between the train logic and the reactor trip breakers, to allow the operator to initiate a reactor trip independent from an automatic reactor trip. When the reactor trip breakers are tripped, the power to the control rod drive mechanisms is interrupted, which allows the control rods to insert into the core by gravity.

The shunt trip attachment, which provides a diverse method from the undervoltage coil for tripping the reactor trip breakers, was installed as part of the AMSAC in response to Generic Letter 83-28, “Generic Implications of Salem ATWS Events.”

AMSAC is classified as Non-Class 1E, except for where it interfaces with the auxiliary feedwater pumps start circuits. AMSAC, also known as the Loss of Feedwater Turbine Trip (LOFWTT), trips the main turbine and starts both the shared motor-driven auxiliary feedwater pumps and the unit specific turbine-driven auxiliary feedwater pump on loss of main feedwater when the main turbine is above 40% nominal power. Class 1E, seismically qualified output relays are used to provide the isolation between the auxiliary feedwater pump start circuits and the AMSAC initiation circuitry. The inputs to AMSAC are separate from and independent of RPS. No sensors are common to the RPS and AMSAC Systems.

The AMSAC System must be capable of operating during a loss-of-offsite-power. AMSAC is not redundant and only has one source of power. Each units AMSAC is powered from a 120 VAC instrument bus, which is derived from a diesel generator power bus.

The equipment installed for AMSAC does not require environmental qualification for the AMSAC function, since it is either located in a mild environment or is not required to operate during or following exposure to potentially harsh environments resulting from design basis accidents. The AMSAC components are qualified for all anticipated environments expected to occur prior to or during an ATWS event. Although environmental qualification is not a design requirement for AMSAC operation, the limit switches on the main feedwater regulating valves are environmentally qualified for High Energy Line Break (HELB) considerations, so that the limit switches added for AMSAC meet the same qualifications as the existing limit switches on the main feedwater regulating valves.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Fire Protection, Environmental Qualification, Anticipated Transients Without Scram, and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the Reactor Protection System containing components subject to an AMR include the four instrument channels that monitor various plant parameters and cause reactor trips based on the coincidence logic required for each specific trip and the AMSAC equipment.

The following systems interface with the Reactor Protection System:

Reactor Coolant	Turbine-Generator and Supporting Systems
Main and Auxiliary Steam	120 VAC Vital Instrument Power
Feedwater and Condensate	125 VDC Power
4160 VAC Power	Control Rod Drive and Indication and Nuclear Process Instrumentation System

System Function Listing

A comprehensive listing of functions associated with the Reactor Protection System, or specific components contained in the system, is provided in the summary below.

Code B	Cri 1	Cri 2	Cri 3				
INTRODUCE EMERGENCY NEGATIVE REACTIVITY TO MAKE THE REACTOR SUBCRITICAL			FP	EQ	PTS	AT	SB
	X						

Comment: The Reactor Protection System contains the reactor trip and trip bypass breakers that initiate an emergency control rod insertion and negative reactivity to make the reactor subcritical.

Code D	Cri 1	Cri 2	Cri 3				
SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION			FP	EQ	PTS	AT	SB
	X						

Comment: The Reactor Protection System monitors parameters related to safe operation and automatically trips the reactor to protect the reactor core against fuel rod cladding damage due to Departure from Nucleate Boiling (DNB). It also assists in protecting against Reactor Coolant System (RCS) damage caused by high system pressure by limiting energy input to the system through reactor trip action.

Code S	Cri 1	Cri 2	Cri 3				
SPECIAL CAPABILITY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: During accidents, the Reactor Protection System provides isolated signals for Reg. Guide 1.97 Type B through E post-accident monitoring variables.

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: The Reactor Protection System provides the following non-safety related functions: manual reactor trip; indication of reactor trip status to the operator at all times; plant startup support and avoidance of unnecessary trips during normal power operation; isolated analog signals and interlock/permissive contacts in support of other plant control systems.

Code X FUNCTION APPLICABLE AT COMPONENT LEVEL	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
	X						

Comment: During accidents, the Reactor Protection System sensors provide isolated signals for Reg. Guide 1.97 Type A post-accident monitoring variables.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Reactor Protection System monitors process parameters for pressurizer level, steam generator level and steam generator pressure to provide indication of safe shutdown.

Code Z2 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
				X			

Comment: The Reactor Protection System contains equipment that is Environmentally Qualified.

Code Z4 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ANTICIPATED TRANSIENTS WITHOUT SCRAM (10 CFR 50.62)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
						X	

Comment: The ATWS Mitigating System Actuation Circuitry (AMSAC) provides a diverse signal to trip the main turbine and start the motor-driven auxiliary feedwater pumps, start the turbine-driven auxiliary feedwater pump for the unit, and isolate blowdown for the unit when a loss of main feedwater is detected.

Code Z5 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
							X

Comment: The Reactor Protection System monitors process parameters for pressurizer level, steam generator level and steam generator pressure.

The Reactor Protection System initiates a reactor trip at the onset of a SBO due to RCP breaker trip(s) and/or turbine trip.

FSAR Reference

Additional Reactor Protection System details are provided in Section 7.2 and Section 7.4 of the FSAR.

License Renewal Drawings

None.

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group’s intended function(s).

2.5.10 Engineered Safety Features Actuation System

Description

The Engineered Safety Features Actuation System detects plant conditions that require automatic Engineered Safety Features (ESF) equipment operation, and actuates the appropriate ESF equipment when preset limits are reached. ESFAS sub-systems monitor plant parameters indicative of different accidents. When the minimum number of channels of a monitored variable reaches a preset limit, trip bistables satisfy coincidence logic for an individual sub-system and the sub-system is automatically initiated. ESFAS sub-systems include: Safety Injection Actuation, Containment Isolation, Containment Ventilation Isolation, Containment Spray Actuation, Steam Line Isolation, Auxiliary Feedwater Pump Start, and Feedwater Isolation.

On the channel level, the four ESFAS channels share protection racks with the four Reactor Protection System channels, because some of the same plant variables used to initiate reactor trip also actuate ESFAS sub-systems. Not all four channels are used for each ESFAS variable, because most ESFAS sub-system coincidence logics rely on less than four channels to actuate. Each channel is energized from a separate AC power feed.

On the train level, the racks for the two ESFAS logic trains are independent and separate from the racks for the two Reactor Protection System logic trains. Each train is energized from a separate DC power feed.

To automatically actuate the various ESFAS sub-systems above, the system monitors the following plant variables: pressurizer pressure, steam line pressure, containment pressure, containment gaseous radioactivity, steam line flow, steam generator level, RCS temperature (T_{avg}), and 4160K VAC bus voltage.

The description above results in some SSCs in this system being considered in-scope in accordance with 10 CFR 54.4(a)(1). In addition, some SSCs are considered in-scope due to Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Engineered Safety Features Actuation System containing components subject to an AMR include the four instrument channels that monitor various plant parameters and cause the appropriate ESF equipment to actuate when preset limits are reached.

The following systems interface with the ESFAS System:

Reactor Coolant	Turbine-Generator and Supporting Systems
Safety Injection	4160 VAC Power
Containment Spray	120 VAC Vital Instrument Power System
Main and Auxiliary Steam	125 VDC Power
Auxiliary Feedwater	

System Function Listing

A comprehensive listing of functions associated with the Engineered Safety Features Actuation System, or specific components contained in the system, is provided in the summary below.

Code D	Cri 1	Cri 2	Cri 3				
SENSE OR PROVIDE PROCESS CONDITIONS AND GENERATE SIGNALS FOR REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION			FP	EQ	PTS	AT	SB
	X						

Comment: The ESFAS detects plant conditions that require automatic ESF equipment operation, and actuates the appropriate ESF equipment when preset limits are reached.

Code S	Cri 1	Cri 2	Cri 3				
SPECIAL CAPABILITY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: During accidents, ESFAS provides isolated signals for RG 1.97 Type B through E post-accident monitoring variables.

Code T	Cri 1	Cri 2	Cri 3				
NON-NUCLEAR SAFETY CLASS FUNCTIONS			FP	EQ	PTS	AT	SB

Comment: ESFAS provides the following NSR functions: the capability to calibrate, test, manually initiate, and reset ESF actuation; signals for status indication and use by plant control systems; containment ventilation isolation on high gaseous radioactivity.

Code X	Cri 1	Cri 2	Cri 3				
FUNCTION APPLICABLE AT COMPONENT LEVEL			FP	EQ	PTS	AT	SB
	X						

Comment: During accidents, ESFAS provides isolated signals for RG 1.97 Type A post-accident monitoring variables.

Code Z2	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)			FP	EQ	PTS	AT	SB
				X			

Comment: The Engineered Safety Features Actuation System contains equipment that is environmentally qualified.

FSAR Reference

Additional ESFAS System details are provided in Section 7.3 of the FSAR.

License Renewal Drawings

None.

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group's intended function(s).

2.5.11 Plant Communications System

Description

The Plant Communications System consists of a broad range of communications equipment. The Plant Communications System provides communication among the plant personnel so that operations can be coordinated. Included within the evaluation boundary is the Gai-Tronics sub-system and radio and repeater sub-system used for fire fighting and safe shutdown activities following some fire events.

The original PBNP Gai-Tronics communication sub-system was designed to support efficient operation and movement of personnel. This sub-system addresses the needs for a building-wide audio communication sub-system. New guidelines resulted in minimum fire related plant communication requirements. Appendix R requires that fixed emergency communication should use voice powered head sets at pre-selected stations and that fixed repeaters installed to permit use of portable radio communication units should be protected from exposure to fire damage. Appendix R requires that fire protection features shall be provided for structures, systems and components required to support safe shutdown.

The communication network needed for safe shutdown outside the control room provides communications between the area of the auxiliary feedwater pumps and the charging pumps, boric acid transfer pumps, diesel generators, and the outside exchange without requiring the control room.

The communications sub-systems available to the Control Room are as follows:

- A five-channel page-party public address sub-system is provided. This system permits communication from any plant area, including the control room, to all other plant areas by a speaker sub-system. The five channels are separate, simultaneous communication party lines.

- An automatic telephone switchboard with its own batteries. The telephone sub-system at PBNP affords a great deal of flexibility and capacity with a connection to the local telephone service provider and microwave connection to the We Energies phone sub-system. Paging capability is also provided via the We Energies phone sub-system or LAN.
- A separate communication sub-system is provided for communication between the control room, the reactor area, and spent fuel pool area during refueling operations.
- AC powered phone jacks, together with an interconnecting wiring sub-system, is provided at each main control panel and at several locations in the plant.
- The public address sub-system is used to broadcast the various plant emergency alarms. The system is also used to communicate the reactor containment evacuation alarm during refueling or outage periods when containment evacuation becomes necessary.
- FM radios link the Control Room to Plant Security, to the Pewaukee System Control Center, and to the Manitowoc County Sheriff.

Additional FM radio sub-systems are used throughout the plant and adjacent areas to enable operations, security, health physics, and maintenance personnel to communicate during normal and/or emergency situations.

There are also emergency telephones within the Technical Support Center (TSC) that provide a direct line to the NRC via the Federal Telecommunications System (FTS) Emergency Notification System (ENS) and to the State of Wisconsin and Manitowoc and Kewaunee Counties via the two-digit dial select telephone. The TSC is also equipped for direct telephone communications with the Control Room and the Emergency Operations Facility and is located adjacent to the Operations Support Center.

The description above results in some SSCs in this system being considered in-scope due to Fire Protection in accordance with 10 CFR 54.4(a)(3).

The portions of the Communications System containing components subject to an AMR includes the equipment necessary to provide emergency communication capabilities to satisfy Appendix R requirements.

The following electrical systems interface with the Plant Communications System:

Miscellaneous AC Power and Lighting	125 VDC Power

System Function Listing

A comprehensive listing of functions associated with the Plant Communications System, or specific components contained in the system, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The Plant Communications System, through the use of portable stationary or portable units, provides remote communication capability between appropriate personnel during fire fighting for personnel and property protection. The Plant Communications System is capable of notifying the fire brigade and other plant personnel of a fire at the plant.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The Plant Communications System is capable of providing plant wide notification immediately following a fire event and portable communication shall be available thereafter.

FSAR Reference

Additional information on the Plant Communications System is provided in Section 7.5.2 of the FSAR.

License Renewal Drawings

None.

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group’s intended function(s).

2.5.12 **13.8K VAC Power System**

Description

The 13.8K VAC Power System is the intermediate voltage power distribution system to both the safety and non safety related electrical loads used at Point Beach Nuclear Plant. The Offsite Power System and the Gas Turbine Generator (G05) are the sources of power to the 13.8K VAC Power System. The 13.8K VAC Power System and G05 do not perform any safety related functions. The 13.8K VAC Power System supplies the 4160 VAC safeguard buses during power operations and all 4160 VAC loads during plant startup, shutdown and following main generator trips. The 13.8K VAC Power System also supplies safe shutdown buses, various plant support loads, gas turbine auxiliaries, 345K VAC switchyard auxiliaries, and the Nuclear Engineering and Training Buildings via various transformers.

The 13.8K VAC Power System supplies offsite power to the Point Beach Nuclear Plant via the 4160 VAC Power System and the 480 VAC Power System. The 13.8K VAC Power System is divided into three buses, one bus dedicated to each unit and a tie bus, which provides for connection to G05. Each unit is normally supplied by a dedicated bus that is served by a high voltage station auxiliary transformer powered from the Offsite Power System. The dedicated buses supply power to the low voltage station auxiliary transformers in each unit. The units can be interconnected to alternate supplies by arranging 13.8K VAC bus tie breakers that connect the dedicated buses to the tie bus. The gas turbine generator G05 is connected to the tie bus by a breaker, and the power it generates can be delivered to either unit when necessary by proper arrangement of the tie breakers. The normal 13.8K VAC electrical arrangement is to have one of the two bus tie breakers closed supplying power to the tie bus. The tie bus supplies the gas turbine auxiliaries as well as the North Service Building transformer and the alternate shutdown transformer.

The G05 is nominally rated at 20 MW and is normally used for spinning reserve, station blackout, and for peaking purposes. This gas turbine unit is connected to the auxiliary electrical sub-system such that it can be paralleled with the normal source of plant startup or standby power. It may also be paralleled with, or serve in lieu of, (under certain conditions) standby power to provide the first source of power to plant electrical loads. The unit is capable of being started and ready to accept partial load in approximately 10 minutes and full load in approximately 15 minutes. It can be considered a small power plant within itself, fully capable of operating independent of the remainder of the plant. The 13.8K VAC Power System will distribute power from G05 to those loads required during a station blackout, to achieve and maintain safe reactor shutdown. During a plant fire in the 4160 VAC switchgear room (or other areas), the 13.8K VAC Power System will provide an alternate source from G05 to those loads required to achieve and maintain safe reactor shutdown via the alternate shutdown transformer.

Startup power for G05 and its auxiliaries is normally supplied by the 13.8K VAC tie bus through a 13.8K/480 VAC auxiliary transformer. The bus is energized from one of the high voltage station auxiliary transformers when G05 is shutdown. When G05 is running, it supplies its own auxiliaries through the same 13.8K VAC tie bus, transformer, and breaker. Because G05 is designed for startup during a loss of offsite power, the auxiliary loads can also be powered from a separate auxiliary diesel generator located in the gas turbine building. An undervoltage device on the secondary of the transformer will sense a loss of normal power and will start the auxiliary diesel generator and align it to supply the G05 auxiliaries. Once G05 is supplying power to the tie bus, its auxiliary loads can be transferred back from the auxiliary diesel to the tie bus. The auxiliary diesel generator also serves as a backup power supply to the Technical Support Center (TSC). The automatic control logic on breaker closure is arranged such that the need for the auxiliary diesel generator to supply gas turbine auxiliaries has priority over the need to supply the TSC loads.

Standby power required during startup, shutdown, and after reactor trip of either unit and normal supply for auxiliaries associated with safeguards is supplied from the 345K VAC transmission sub-system via the high voltage and low voltage station auxiliary transformers, respectively. After a turbine generator trip, the auxiliaries on the 4160 VAC Power System non-safeguards buses being fed by the unit auxiliary transformer are transferred by a fast bus transfer scheme to the unit's station low voltage auxiliary transformer. Each low voltage station auxiliary transformer can supply all the auxiliary loads for its unit.

The description above results in some SSCs in this system being considered in-scope due to Fire Protection and Station Blackout in accordance with 10 CFR 54.4(a)(3).

The portions of the 13.8K VAC Power System containing components subject to an AMR includes the equipment necessary to provide standby power required during startup, shutdown, and reactor trip of either unit and normal supply for auxiliaries associated with safeguards. In addition, the system is needed as an alternate AC source during recovery after the coping period, to maintain safe reactor shutdown following an SBO event. It also provides for restoration of offsite power following the recovery to meet the NRC LR requirements beyond those in the CLB that meet the requirements of 10 CFR 50.63.

The following electrical systems interface with the 13.8K VAC Power System:

Emergency Power	480 VAC Power
125 VDC Power	4160 VAC Power
Offsite Power	

System Function Listing

A comprehensive listing of functions associated with the 13.8K VAC Power System, or specific components contained in the system, is provided in the summary below.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: The 13.8K VAC Power System supplies the 4160 VAC safeguard buses during power operations and all 4160 VAC loads during plant startup, shutdown and following main generator trips. The Gas Turbine Generator (G05) can be connected to the 13.8K VAC tie bus and paralleled with the normal source of plant startup power or used as standby power. It may also be paralleled with, or serve in lieu of, (under certain conditions) standby power to provide the first source of power to plant electrical loads.

Code Z1 LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR FIRE PROTECTION (10 CFR 50.48)	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
			X				

Comment: The 13.8K VAC Power System provides power to the 4160 VAC Power System and the 480 VAC Power System alternate shutdown buses to support safe shutdown components.

During a plant fire in the 4160 VAC switchgear room (or other areas), the 13.8K VAC Power System will provide an alternate source from G05 to those loads required to achieve and maintain safe reactor shutdown via the alternate shutdown transformer.

Code Z5	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S 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)							X

Comment: The 13.8K VAC Power System provides power to the 4160 VAC Power System and the 480 VAC Power System alternate shutdown buses to support safe shutdown components.

The 13.8K VAC Power System will distribute power from the G05 Gas Turbine generator to those loads required during a station blackout, to achieve and maintain safe reactor shutdown. In addition, the system provides for redundant paths through the respective unit's high voltage station auxiliary transformer for the restoration of offsite power following a SBO event to meet the NRC LR requirements beyond those in the CLB which meet the requirements of 10 CFR 50.63.

FSAR Reference

Additional 13.8K VAC Power System details are provided in Section 8.2 and Section 8.9 of the FSAR.

License Renewal Drawings

The license renewal drawings for the 13.8K VAC Power System are listed below:

Common
LR-ELECTRICAL-E1

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group’s intended function(s).

2.5.13 Radiation Monitoring System

System Description

The Radiation Monitoring System (RMS) monitors radiation levels and fluid activities at various locations throughout the plant. It is designed to accomplish three functions under normal and accident conditions:

1. Provide direct indication of and, if necessary, warning of radiation levels in the plant;
2. Measure gas releases from the plant vent stacks to provide indication of potential airborne activity; and

3. Initiate isolation and control functions on certain effluent streams.

In conjunction with regular and special radiation surveys and with radio chemical analyses performed by the plant staff, the RMS provides information to the operator to determine plant conditions and/or emergency status. It also provides adequate information and warning for the safe operation of the plant and assurance that personnel exposure does not exceed 10 CFR 20 limits.

Radiation detectors, microprocessors, and operator input/output terminals are integrated in the RMS in order to achieve the desired functions. The radiation detectors sense radiation through one of the physical processes of either ionization or scintillation. The radiation detectors can be further characterized by their monitoring function:

- Area Monitor
- Process Monitor
- System Level Particulate, Iodine, and Noble Gas Monitor (SPING)

The RMS consists of eight data acquisition modules (DAMs); four system level particulate, iodine and noble gas monitors (SPINGs); two system servers (SSs); and interfaces to the Plant Process Computers System (PPCS). It is a microprocessor based radiation detection sub-system. The eight DAMs and four SPING monitors provide the necessary microprocessing capability for the plant's radiation detectors. Each SPING has a DAM built into it, and each DAM is capable of serving nine detector (digital) inputs and six analog inputs. Each DAM also has a microcomputer which performs the tasks of data acquisition, history file management, operational status check, alarm determination and interface with the input/output terminals. Each DAM/SPING is designed to operate its detectors in a stand-alone manner.

The portion of the integrated RMS which is within the scope of License Renewal consists of those detectors and DAMs which monitor the control room environment for iodine and noble gas. They provide control for portions of the control room ventilation sub-system. They operate in a controlled environment.

The entire Radiation Monitoring System is powered from the 120 VAC Vital Instrument Power System. The instrument bus provides power to each DAM; the DAM provides power to each of its associated channels. In addition; each DAM is equipped with a battery, which provides for eight hours of continuous operation in the event of a power failure.

Independent of the integrated RMS described above is a separate containment high-range RMS that exists for each unit to sense high radiation levels, which might exist in a post-accident environment. Each unit's containment high-range RMS consists of three radiation detectors per containment structure and their associated electronics. Each detector feeds a control room indicator that indicates on a logarithmic scale over a range of 1 to 10^8 Roentgen/hr. This sub-system is environmentally qualified.

Since some SSCs in the Radiation Monitoring System are non-safety related and their failure could affect the capability of SR SSCs to perform their safety function, they are considered to be in-scope in accordance with 10 CFR 54.4(a)(2). In addition, some SSCs are considered in-scope due to Environmental Qualification in accordance with 10 CFR 54.4(a)(3).

The portions of the Radiation Monitoring System containing components subject to an AMR include the equipment necessary to monitor the containment post-accident and provide for monitoring and control of control room habitability. Containment boundary components such as piping and valves are considered as part of the Containment Unit 1/2 Building Structure.

The following systems interface with the Radiation Monitoring System (Note: the pressure boundary interfaces are evaluated within the system being monitored):

120 VAC Vital Instrument Power	Essential Ventilation

System Function Listing

A comprehensive listing of functions associated with the Radiation Monitoring System, or specific components contained in the system, is provided in the summary below.

Code S SPECIAL CAPABILITY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Provide radiation monitoring devices to support operator indication of plant conditions in accordance with the requirements of RG 1.97, providing signals for Reg. Guide 1.97 Type C and E post-accident monitoring variables.

Code T NON-NUCLEAR SAFETY CLASS FUNCTIONS	Cri 1	Cri 2	Cri 3				
			FP	EQ	PTS	AT	SB

Comment: Provide radiation monitoring for containment atmosphere and discharge paths.

Provide continuous monitoring of in-plant radiation, airborne activity, and liquid activity throughout the Primary Auxiliary Building.

Code Y	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 2 - CONTAINS NON SAFETY RELATED SSC'S WHOSE FAILURE COULD PREVENT SATISFACTORY ACCOMPLISHMENT OF A SAFETY RELATED FUNCTION			FP	EQ	PTS	AT	SB
		X					

Comment: Radiation Monitoring System detectors provide iodine and noble gas monitoring and control of the control room environment to ensure operator habitability.

Code Z2	Cri 1	Cri 2	Cri 3				
LICENSE RENEWAL CRITERION 3 - CONTAINS SSC'S RELIED UPON IN SAFETY ANALYSES OR PLANT EVALUATIONS TO PERFORM A FUNCTION THAT DEMONSTRATES COMPLIANCE WITH THE COMMISSION'S REGULATIONS FOR ENVIRONMENTAL QUALIFICATION (10 CFR 50.49)			FP	EQ	PTS	AT	SB
				X			

Comment: The Radiation Monitoring System contains equipment for the Containment High-Range Radiation Monitors that is environmentally qualified.

FSAR Reference

Additional Radiation Monitoring System details are provided in Section 5.2 and Section 11.5 of the FSAR.

License Renewal Drawings

None.

Components Subject to an AMR

The commodity groups for this system that require aging management review are addressed in Table 2.5-1 along with each commodity group's intended function(s).

Table 2.5-1 Electrical Commodity Groups

Commodity Group	Intended Function
ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS (ALL ELECTRICAL POWER AND I&C SYSTEMS)	DELIVER VOLTAGE, CURRENT, OR SIGNAL

Table 2.5-1 Electrical Commodity Groups

Commodity Group	Intended Function
ELECTRICAL CABLES AND CONNECTIONS USED IN INSTRUMENTATION CIRCUITS NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS THAT ARE SENSITIVE TO REDUCTION IN CONDUCTOR INSULATION (NUCLEAR INSTRUMENTATION AND RADIATION MONITORING SYSTEMS)	DELIVER VOLTAGE, CURRENT, OR SIGNAL
ELECTRICAL CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS THAT ARE EXPOSED TO BORATED WATER LEAKAGE (SOME ELECTRICAL AND I&C SYSTEMS)	DELIVER VOLTAGE, CURRENT, OR SIGNAL
ELECTRICAL PENETRATION ASSEMBLIES (ELECTRICAL POWER SYSTEMS 4160 VAC OR LESS, AND ALL I&C SYSTEMS)	DELIVER VOLTAGE, CURRENT, OR SIGNAL
HIGH-VOLTAGE INSULATORS (OFFSITE POWER SYSTEM)	ELECTRICALLY ISOLATE AND SUPPORT
INACCESSIBLE MEDIUM-VOLTAGE (2K VAC TO 15K VAC) CABLES AND CONNECTIONS (E.G., INSTALLED IN CONDUIT OR DIRECT BURIED) NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS (4160 VAC AND 13.8K VAC POWER SYSTEMS)	DELIVER VOLTAGE, CURRENT, OR SIGNAL

Table 2.5-1 Electrical Commodity Groups

Commodity Group	Intended Function
PHASE BUS (480 VAC, 4160 VAC, AND 13.8K VAC POWER SYSTEMS)	DELIVER VOLTAGE, CURRENT, OR SIGNAL ELECTRICALLY ISOLATE AND SUPPORT
SWITCHYARD BUSES AND CONNECTIONS (OFFSITE POWER SYSTEM)	DELIVER VOLTAGE, CURRENT, OR SIGNAL
TRANSMISSION CONDUCTORS (OFFSITE POWER SYSTEM)	DELIVER VOLTAGE, CURRENT, OR SIGNAL

Section 2.5 References

1. SAND96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,” Prepared by Ogden Environmental and Energy Services under contract to Sandia National Laboratories for the U.S. Department of Energy, in cooperation with the Electric Power Research Institute.
2. IEEE 100-1984, “The IEEE Standard Dictionary of Electrical and Electronics Terms,” The Institute of Electrical and Electronic Engineers, Inc.

3.0 AGING MANAGEMENT REVIEW RESULTS

For those structures and components that are subject to aging management review, 10 CFR 54.21(a)(3) of the license renewal rule requires demonstration that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation.

This section describes the results of the aging management reviews for those structures and components that were identified in Section 2.0, Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results.

3.0.1 Review Methodology

The overall process by which aging effects requiring management were identified and evaluated is summarized in this section.

For each structure and component (SC) that is in-scope, long-lived, and passive, PBNP performed an aging management review to show that the intended function (IF) of the SC will be maintained consistent with the CLB under all design conditions during the period of extended operation. To do this, PBNP identified information that is pertinent to aging of the SC. This information includes the material of construction, the normal operating environment, and the stressors that are associated with the component. Both industry and plant operating experience were reviewed to determine any information that is applicable to the SC being reviewed.

Based on this information, the aging effects that can potentially affect the SC's ability to meet its IF were identified. The final step in the process was to identify the aging management programs that will prevent, mitigate or detect the aging effect, such that the IF will be maintained. If the aging management program is one that detects the effects of aging, it must do so in a timely manner such that the aging is detected prior to a loss of IF. In all cases, the information in the application as well as supporting documentation demonstrates that the program is effective. This was accomplished by a review of plant and industry operating experience and inspections that have been previously performed.

The determination of the aging management programs that are credited for managing aging for the period of extended operation include a review of the programs. The first choice was to credit programs currently in place at PBNP that manage the effects of aging. Alternatively, existing programs will be modified or enhanced so that they will manage the effects of aging. Finally new programs will be created where aging management is required, but no programs currently exist. All of these programs were reviewed against the 10 elements delineated by the NRC in NUREG-1801, and/or NUREG-1800.

3.0.1.1 Determination of Materials of Construction

Materials of construction were identified for all systems, structures and components subject to aging management review. Sources of information used to identify materials of construction included original Westinghouse and Bechtel equipment and material specifications, vendor technical manuals and drawings, fabrication drawings, piping and instrument drawings, and piping line specifications. Field walkdowns were also used to identify/verify materials of construction for some components.

3.0.1.2 Determination of Operating Environments

Internal operating environments were defined by fluid medium and chemistry (i.e., treated water, raw water, lubricating oil and fuel oil, air/gas, etc.), service temperature, and condition of fluid flow. External environments were defined by plant location, including radiation, temperature and humidity (i.e., containment, indoor with no air-conditioning, outdoor with exposure to weather), exposure to soil/soil water (i.e., buried), embedment in concrete, and exposure to borated water leaks.

Table 3.0-1 and Table 3.0-2 contain descriptions of the internal and external service environments at PBNP which are used in subsequent sections. Within this Application, some of the internal environments have been subdivided into subgroups based on temperature or flow rate. The subgroups are identified in the Description column in Table 3.0-1.

3.0.1.3 Component Grouping by Material/Environment Combination

The aging mechanisms and effects that apply to a structure or component are determined by the material(s) of construction and operating environment (including temperature and stress) to which the material is exposed. Structures or components constructed of the same material and exposed to the same environment would therefore be susceptible to the same aging mechanisms and effects. As a result, on a system basis, structures and components were grouped together according to material/environment combinations. This facilitated the aging management review process, in that a single aging management review could be performed for a system specific group of structures or components.

3.0.1.4 Aging Effects Analysis - Non-Class 1 Mechanical Systems and Components

Aging effects requiring management for Non-Class 1 systems and components were determined using the evaluation processes described in standard industry guidance for aging evaluation of mechanical systems and components. Systems and components were evaluated by applying a set of material/environment-based rules derived from known age-related degradation mechanisms documented in the technical literature and published industry operating experience. A plant-specific review of this industry guidance document was conducted to demonstrate applicability of this document at PBNP and to provide corrections and/or enhancements to criteria for evaluating aging of specific materials in certain environments.

3.0.1.4.1 Treated Water Systems

In accordance with NUREG-1801 for treated water systems, aging mechanisms and effects were identified and evaluated without crediting the mitigative effects of water chemistry controls.

3.0.1.4.2 Protective Coatings

Coatings are used at PBNP to protect the surfaces of steel components in mechanical systems and structures. Although the benefits derived from protective coatings are recognized, coatings, in and of themselves, do not perform License Renewal intended functions. Therefore, protective coatings are not credited with managing the effects of aging. However, the condition of steel surfaces protected by coatings is evaluated during inspections directed by aging management programs at PBNP. When evidence of superficial surface corrosion caused by coating degradation is found, the coating is evaluated and repaired in accordance with plant procedures. That notwithstanding, protective coatings applied to surfaces in containment are monitored within the current licensing basis in accordance with PBNP commitments under Generic Letter 98-04 (or refer to GSI-191).

3.0.1.4.3 Position on SCC of Austenitic Stainless Steel

The threshold temperature for the onset of stress corrosion cracking of austenitic stainless steels in the presence of halides (>150 ppb) and sulfates (>100 ppb) is generally agreed to be approximately 140°F (Reference 1 and Reference 2). The validity of this threshold temperature is also supported by industry operating experience. This threshold temperature has been applied to austenitic stainless steels in all environments evaluated in this LRA. However, it should be noted that the Water Chemistry Control Program (supplemented by one-time inspections in stagnant or low-flow areas) is the aging management program credited for managing cracking due to SCC in treated water systems. This aging management approach is consistent with NUREG-1801.

3.0.1.4.4 **Position on IGA/IGSCC of Austenitic Stainless Steels**

Cracking of austenitic stainless steels due to IGA/IGSCC requires a threshold level of grain boundary sensitization and a threshold temperature of approximately 140°F (Reference 1 and Reference 2). IGA/IGSCC is not a credible aging mechanism for welded austenitic stainless steel piping and components at PBNP due to controls imposed on heat input and interpass temperature during fabrication which limited grain boundary sensitization in heat affected zones of welded joints. Susceptibility of austenitic stainless steels to IGA/IGSCC may be increased only after prolonged exposure to elevated temperatures above 482°F.

3.0.1.4.5 **Position on SCC of SA 193 Grade B7 Bolting Materials**

Although there have been a few reported cases of cracking of bolting in the industry caused by SCC, these have been attributed to susceptible high yield strength materials exposed to aggressive environments, such as lubricants containing molybdenum disulfide.

However, a survey of industry experience, technical literature, and laboratory corrosion studies documented in EPRI Report NP-5769 (Reference 3) indicates that SCC should not be a concern for closure bolting in nuclear power plant applications if the specified minimum yield strength is <150 Ksi. For quenched and tempered low-alloy steels typically used for closure bolting (e.g., SA193, Grade B7), susceptibility to SCC is controlled by yield strength. The minimum yield strength specified in SA193 for Grade B7 material is 105 Ksi, which is well below the threshold value of 150 Ksi identified in EPRI Report NP-5769. Furthermore, the selection and use of fastener lubricants for pressure boundary components has been controlled by the PBNP Quality Assurance Program as part of the response to IE Bulletin 82-02. Limits are also imposed on levels of contaminants such as chlorides and sulfur compounds (including molybdenum disulfide) in lubricants and sealant compounds. Therefore, it is reasonable to conclude that failure by SCC should not be a significant issue for SA193 Grade B7 bolting materials. PBNP operating experience supports this conclusion.

3.0.1.4.6 Generic Component Assets

It was recognized that certain items/assets such as carbon/low-alloy steel closure bolting or other carbon steel components are present in almost every mechanical system or structure and therefore may be conveniently treated as commodity groups. To facilitate aging management review of such items, generic assets were created in every system and structure to account for the presence of closure bolting and external surfaces of carbon steel components which are subject to the effects of aging. Carbon steel components (CS components) are identified as a specific commodity group to ensure that carbon steel components potentially exposed to borated water leaks are evaluated. The normal external operating environment is evaluated with the specific system-identified components.

Aging effects requiring management for closure bolting were assigned to the generic asset in each system/structure and appropriate aging management programs were identified and credited. For borated water systems or non-borated water systems in close proximity to borated water systems, the potential for boric acid corrosion of carbon/low-alloy steel closure bolting, structural bolting, and external surfaces of equipment and structural members was recognized and accounted for by assigning the applicable aging effects to the generic assets. Appropriate aging management programs were then identified and credited.

3.0.1.5 Aging Effects Analysis - ASME Class 1 Systems, Structures and Components

Aging effects requiring management for ASME Class 1 systems, structures, and components were determined using the information and guidance presented in Westinghouse Generic Topical Reports (GTRs). The following ASME Class 1 components were evaluated using the GTRs:

- Reactor Pressure Vessel
- Reactor Vessel Internals (NRC Reviewed)
- Steam Generators
- Pressurizer (NRC Reviewed)
- Class 1 Piping (NRC Reviewed)
- Reactor Coolant System Supports (NRC Reviewed)

In addition, the Containment Structure (NRC Reviewed) is addressed under a Westinghouse GTR.

The GTRs have undergone extensive peer review and, in some cases, NRC review. In addition, they contain thorough reviews of equipment maintenance histories as well as discussions and assessments of industry/regulatory issues. For those GTRs with U.S. NRC Final Safety Evaluation Reports (FSERs), detailed responses to all Applicant Action Items were prepared, and are included in the appropriate sections of this LRA. For each component that utilized a NRC-reviewed GTR for aging management, a short description demonstrating the applicability of the GTR to PBNP is included.

3.0.1.6 Aging Effect Analysis - Plant Structures and Structural Components

Aging effects requiring management for Plant Structures and Structural Components (including Component Supports, Fire Barriers, and Cranes, Hoists, and Lifting Devices) were determined using the evaluation processes described in standard industry guidance for aging evaluation of structures and structural components. Aging mechanisms and effects identified in the EPRI document for structural materials were derived from a number of sources, including collective nuclear plant operating experience and relevant operating experience from other industries. A plant-specific review of this guidance document was conducted to evaluate applicability of various aging mechanisms at PBNP (see Section 3.0.1.9).

3.0.1.7 Industry and Plant-Specific Operating Experience Review

A thorough review of appropriate industry and plant-specific operating experience was conducted to confirm that applicable aging effects had been identified. Industry operating experience sources included NRC Generic Publications, INPO Significant Event Evaluation and Information Network (SEE-IN) documents, Westinghouse Generic Technical Reports (GTRs), Westinghouse Nuclear Safety Advisory Letters (NSALs), Technical Bulletins (TBs) and Info Grams (IGs), NUREG-1801 (Generic Aging Lessons Learned (GALL) report), and prior License Renewal Applications (LRA). Plant-specific operating experience sources included Corrective Action documents, NRC Notices of Violations (NOVs), Licensee Event Reports (LERs), Incident Investigations, Non-Conformance Reports, Root Cause Evaluations, and Maintenance Work Orders. This review was conducted not only to confirm that the aging effects determined by material/environment-based rules were appropriate, but also to assure that any additional plant-specific aging mechanisms and related effects were identified for management.

3.0.1.8 Assignment of Aging Management Programs

Appropriate aging management program(s) credited for managing each aging effect were assigned to each structure or component evaluated in the aging management review process. Aging management programs are described in Appendix B of this Application.

3.0.1.9 Standard Industry Guidance Document Review (Structures and Structural Components)

A technical review of standard industry guidance for aging evaluation of structures and structural components was conducted to evaluate the applicability of aging mechanisms identified for structural materials at Point Beach. This included a review of original construction contractual requirements, specifications for concrete structures and other materials, site-specific environments, and plant operating experience. Certain aging mechanisms/effects were determined not to be applicable at Point Beach.

Concrete/grout was analyzed for 15 possible aging effects/mechanisms. The Point Beach specific environment and/or concrete/grout mixes were considered when determining possible aging effects. Of the 15 aging effects analyzed, 3 were identified as aging effects for the Point Beach structures. Concrete/grout aging effects at Point Beach include abrasion in a raw water environment, cracking-masonry block, and cracking-service induced, both in an indoor or outdoor environment.

An example of an aging effect not applicable at Point Beach is freeze-thaw. Freeze-thaw is not significant, as stated in NUREG-1801, if the concrete mix meets the air content (entrained air 3-6%) and water-to-cement ratio (0.35-0.45) specified in ACI 318-63 or ACI 349-85. Since each of the four contract specifications for concrete at Point Beach insures air contents and water-to-cement ratios are within the recommendations stated in NUREG-1801, loss of material due to freeze-thaw is not an aging effect requiring management.

Aggressive chemical attack of concrete/grout is predicated on having an aggressive environment, be it an air environment, soil, ground or lake water. By analysis, the concrete/grout at Point Beach is not exposed to an aggressive environment, therefore, loss of material and change in material properties due to aggressive chemical attack are not aging effects requiring management. Periodic chemical analyses of the soil, ground water, and lake water will be performed to ensure the below-grade environment remains chemically non-aggressive for the period of extended operation.

Not withstanding the concrete/grout analysis for aging effects and the conclusion that the majority are in the no aging effects category, all concrete/grout at Point Beach that is within the scope of license renewal, will be managed for aging. This is in keeping with the NRC's position that aging of concrete elements of the containment and other Class 1 structures should be managed.

3.0.1.10 Standard Industry Guidance Document Review (Electrical Commodities)

A technical review of standard industry guidance for aging evaluation of electrical commodities was conducted to evaluate the applicability of aging mechanisms identified for electrical components at Point Beach. This included a review of original construction requirements, specifications for selected electrical components and other insulating materials, site-specific environments, and plant operating experience.

3.0.1.11 Review of NUREG-0933

NUREG-0933 has been reviewed in accordance with the guidance provided in Appendix A.3 of the Standard Review Plan. As a result of this review, the following generic safety issues (GSI) have been evaluated for license renewal and have been addressed in the LRA:

- GSI-168, Environmental Qualification of Electrical Equipment, is addressed in Section 4.8.1, Environmental Qualification of Electric Equipment.
- GSI-190, Fatigue Evaluation of Metal Components for 60-Year Plant Life, is addressed in Section 4.3.10, Environmentally Assisted Fatigue.
- GSI-191, Assessment of Debris Accumulation on PWR Sump Performance, is addressed in Section 3.0.1.4.2.

3.0.2 Aging Management Review Results Display Method

This section provides the results of the aging management review for those structures and components identified in Section 2.0 as being subject to aging management review.

Descriptions of the internal and external service environments which were used in the aging management review to determine aging effects requiring management are included in Table 3.0-1, Internal Service Environments and Table 3.0-2, External Service Environments. The environments used in the aging management reviews are listed in the Environment column.

Most of the Aging Management Review (AMR) results information in Section 3 is presented in the following two tables:

- Table 3.x.1 - where '3' indicates the LRA section number, 'x' indicates the subsection number from NUREG-1801, Volume 1, and '1' indicates that this is the first table type in Section 3. For example, in the Reactor Coolant System subsection, this table would be number 3.1.1, in the Engineered Safety Features subsection, this table would be 3.2.1, and so on. For ease of discussion, this table will hereafter be referred to in this Section as “Table 1."
- Table 3.x.2-y - where '3' indicates the LRA section number, 'x' indicates the subsection number from NUREG-1801, Volume 1, and '2' indicates that this is the second table type in Section 3; and 'y' indicates the system table number. For example, for the Reactor Vessel, within the Reactor Coolant System subsection, this table would be 3.1.2-1 and for the Reactor Vessel Internals, it would be table 3.1.2-2. For the Containment Spray System, within the Engineered Safety Features subsection, this table would be 3.2.2-1. For the next system within the ESF subsection, it would be table 3.2.2-2. For ease of discussion, this table will hereafter be referred to in this section as “Table 2."

Table Description

NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” contains the staff's generic evaluation of the 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 extended period of operation. The evaluation results documented in the report indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components, within the scope of license renewal, without change. The report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. In order to take full advantage of NUREG-1801, a comparison between the AMR results and the tables of NUREG-1801 has been made. The results of that comparison are provided in the two tables.

Table 1 (Figure 3.0-1)

The purpose of Table 1 is to provide a summary comparison of how the applicant aligns with the corresponding tables of NUREG-1801, Volume 1. The table is essentially the same as Tables 1 through 6 provided in NUREG-1801, Volume 1, except that the “Type” column has been replaced by an “Item Number” column and the “Item Number in GALL” column has been replaced by a “Discussion” column.

The “Item Number” column provides the reviewer with a means to cross-reference from Table 2 to Table 1.

The “Discussion” column is used by the applicant to provide clarifying/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 (including a hyperlink if possible)
- The name of a plant specific program being used (and a hyperlink to the program if possible)
- Exceptions to the NUREG-1801 assumptions
- A discussion of how the line item is consistent with the corresponding line item in NUREG-1801, Volume 1, when that may not be intuitively obvious
- A discussion of how the line item is different than the corresponding line item in NUREG-1801, Volume 1, when it may appear to be consistent (e.g., when there is exception taken to an aging management program that is listed in NUREG-1801, Volume 1)

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 row with the corresponding NUREG-1801, Volume 1 table row, thereby allowing for the ease of checking consistency.

Table 2 (Figure 3.0-2)

Table 2 provides the detailed results of the aging management reviews for those components identified in LRA Section 2 as being subject to aging management review. There will be a Table 2 for each of the sub-systems within a “system” grouping. For example, for a PWR, the Engineered Safety Features System Group contains tables specific to Containment Spray, Containment Isolation, Emergency Core Cooling System, etc.

Table 2 consists of the following nine columns:

- Component Type
- Intended Function
- Material
- Environment
- Aging Effect Requiring Management
- Aging Management Programs
- NUREG-1801 Volume 2 Item

- Table 1 Item
- Notes

Component Type

The first column identifies all of the component types from Section 2 of the LRA that are subject to aging management review. They are listed in alphabetical order.

Intended Function

The second column contains the license renewal intended functions (including abbreviations where applicable) for the listed component types. Definitions and abbreviations of intended functions are contained within the Intended Functions table of LRA Section 2.

Material

The third column lists the particular materials of construction for the component type.

Environment

The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated and a list of these environments is provided in the Internal Service Environments and External Service Environments tables of LRA Section 3.

Aging Effect Requiring Management

As part of the aging management review process, the applicant determines any aging effects requiring management for the material and environment combination in order to maintain the intended function of the component type. These aging effects requiring management are listed in column five.

Aging Management Programs

The aging management programs used to manage the aging effects requiring management are listed in column six of Table 2.

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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-1801, Volume 2 with consideration given to the standard notes, to identify consistencies. When they are identified, they are documented by noting the appropriate

NUREG-1801, Volume 2 item number in column seven of Table 2. If there is no corresponding item number in NUREG-1801, Volume 2, this row in column seven is left blank. That way, a reviewer can readily identify where there is correspondence between the plant specific tables and the NUREG-1801, Volume 2 tables.

Table 1 Item

Each combination of component, material, environment, aging effect requiring management, and aging management program that has an identified NUREG-1801 Volume 2 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Figure 3.0-1 is listed in column eight of Table 2. If there is no corresponding item in NUREG-1801, Volume 1, this row in column eight is left blank. That way, the information from the two tables can be correlated.

Notes

In order to realize the full benefit of NUREG-1801, each applicant needs to identify how the information in Table 2 aligns with the information in NUREG-1801, Volume 2. This is accomplished through a series of notes. All note references with letters are standard notes that will be the same from application to application throughout the industry. Any notes the plant requires which are in addition to the standard notes will be identified by a number and deemed plant specific.

Table Usage

Table 1

The reviewer evaluates each row in Figure 3.0-1 by moving from left to right across the table. Since the Component, Aging Effect/Mechanism, Aging Management Programs and Further Evaluation Recommended information is taken directly from NUREG-1801, Volume 1, no further analysis of those columns is required. The information intended to help the reviewer the most in this table is contained within the Discussion column. Here the reviewer will be given information necessary to determine, in summary, how the applicant's evaluations and programs align with NUREG-1801, Volume 1. This may be in the form of descriptive information within the Discussion column or the reviewer may be referred to other locations within the LRA for further information (including hyperlinks where possible/practical).

Table 2

Figure 3.0-2 contains all of the Aging Management Review information for the plant, whether or not it aligns with NUREG-1801. 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-1801, Volume 2, this will be identified by a referenced item number in column seven, NUREG-1801, Volume 2 Item. The reviewer can refer to the item number in NUREG-1801, Volume 2, if desired, to verify the correlation. If the column is blank, the applicant was unable to locate an appropriately corresponding combination in NUREG-1801, Volume 2.

In some cases, the information in NUREG-1801, Volume 2 (component type, material, environments, aging effect, and program), was not completely consistent with the plant-specific information generated during the aging management reviews. In these cases, parenthesis were placed around the Volume 2 item number, to show that this line item was not an exact match. In these instances, the difference was addressed in the Notes.

In a few other cases, an applicable Volume 2 line item number was designated from a different chapter, if there was no appropriate line item number in the associated chapter. These line item numbers were also annotated with parenthesis, and the details were addressed in the Notes.

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-1801. Program details may be found in Appendix B. There may be a hyperlink directly to the corresponding row in Table 1 as well. In addition, as discussed above for the Volume 2 line items, parenthesis are used similarly for the Table 1 Items.

Table 2 provides the reviewer with a means to navigate from the components subject to Aging Management Review (AMR) in LRA Section 2, all the way through the evaluation of the programs that will be used to manage the effects of aging of those components.

A listing of the abbreviations used in this section is provided in Section 1.5.

Table 3.0-1 Internal Service Environments

Environment	Description
Treated Water - Primary, T<140°F	Treated water containing boric acid in the Reactor Coolant System (RCS). The chemistry of this water is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. Includes consideration of stagnant, low flow <3 fps.
Treated Water - Primary, T>480°F	Treated water containing boric acid in the Reactor Coolant System (RCS). The chemistry of this water is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. Includes consideration of stagnant, low flow <3 fps.
Treated Water - Primary, 140°F<T<480°F	Treated water containing boric acid in the Reactor Coolant System (RCS). The chemistry of this water is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. Includes consideration of stagnant, low flow <3 fps.
Treated Water - Secondary, T>120°F	Demineralized, deaerated water; secondary water chemistry is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program and includes high energy piping in Main and Auxiliary Steam, Feedwater and Condensate, and Auxiliary Feedwater. Includes steam and consideration of stagnant, low flow <3 fps.
Treated Water - Secondary, T<120°F	Demineralized, deaerated water; secondary water chemistry is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. Includes portions of Auxiliary Feedwater, Feedwater and Condensate, and Plant Sampling Systems. Includes consideration of stagnant, low flow <3 fps.
Treated Water - Borated, T<140°F	Treated water containing boric acid in systems other than the Reactor Coolant System, i.e., Plant Sampling, CVCS, Residual Heat Removal, Safety Injection, Spent Fuel Cooling, Containment Spray, and Waste Disposal Systems. Borated water chemistry is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. Includes consideration of stagnant, low flow <3 fps.
Treated Water - Borated, T>140°F	Treated water containing boric acid in systems other than the Reactor Coolant System, i.e., Plant Sampling, CVCS, Residual Heat Removal, Safety Injection, Spent Fuel Cooling, Containment Spray, and Waste Disposal Systems. Borated water chemistry is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. Includes consideration of stagnant, low flow <3 fps.
Treated Water - Other	Treated water is demineralized water that may be deaerated and include corrosion inhibitors and biocides or some combination of these treatments. The chemistry of this water is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. PBNP treated water systems include CVCS, Emergency Power, and Component Cooling Water Systems.

Table 3.0-1 Internal Service Environments

Environment	Description
Treated Water - Other (Stagnant)	Treated water is demineralized water that may be deaerated and include corrosion inhibitors and biocides or some combination of these treatments. The chemistry of this water is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. PBNP treated water systems include CVCS, Emergency Power, and Component Cooling Water Systems. Includes consideration of stagnant, low flow <3 fps.
Treated Water - Other (Velocity)	Treated water is demineralized water that may be deaerated and include corrosion inhibitors and biocides or some combination of these treatments. The chemistry of this water is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program. PBNP treated water systems include CVCS, Emergency Power, and Component Cooling Water Systems. Includes consideration of high velocity, change in flow direction.
Raw Water	The Raw Water category at PBNP includes the lake water used for Service Water and Fire Protection.
Raw Water (Stagnant)	The Raw Water category at PBNP includes the lake water used for Service Water and Fire Protection. Includes consideration of stagnant, low flow <3 fps.
Raw Water (Velocity)	The Raw Water category at PBNP includes the lake water used for Service Water and Fire Protection. Includes consideration of high velocity, change in flow direction.
Raw Water Drainage	Fluids collected in building drains. These can be treated (primary, borated, secondary, or other), raw water (Service Water), fuel oil or lubricating oil.
Oil and Fuel Oil	This category comprises either lubricating oil or diesel fuel oil. PBNP systems having this internal environment include the Emergency Power and Fire Protection.
Oil and Fuel Oil - Pooling	This category comprises either lubricating oil or diesel fuel oil. PBNP systems having this internal environment include the Emergency Power and Fire Protection. Includes potential for water pooling.
Air and Gas	The environments in this category include dehumidified atmospheric air, dry/filtered instrument air, nitrogen, hydrogen, helium, and halon. PBNP systems exposed to this internal environment include the Plant Air, Emergency Power, Essential Ventilation, Containment Ventilation, Waste Disposal, Fire Protection, etc. Note that air operated valves assigned to balance of plant systems are also exposed to this environment.
Air and Gas - Wetted, T<140°F	The environments in this category include moist atmospheric air, and undried compressed air. PBNP systems exposed to this internal environment include the Plant Air, Emergency Power, Non-Class 1 RCS Components, Essential Ventilation, Containment Ventilation, Waste Disposal, Fire Protection, etc.

Table 3.0-1 Internal Service Environments

Environment	Description
Air and Gas - Wetted, T>140°F	The environments in this category include moist atmospheric air, where temperatures are normally >140°F.

Table 3.0-2 External Service Environments

Category	Description
Borated Water Leaks	Exposed to borated water leaks
Buried	Exposed to soil/fill, which includes possible contact with ground water
Concrete	Embedded/encased in concrete
Containment	Air, temperature of 50°F-105°F general accessible areas (specific hot spots up to 135°F - worst case equipment in close proximity to RC Loop Piping - 150°F), maximum relative humidity 100%. Normal 40-year radiation dose 5.8E+7 rads (excluding equipment located inside the reactor cavity). No direct exposure to weather.
Indoor - Air Conditioning	Specific temperature range/humidity dependent on specific area location. Nominal temperature 75°F ± 10°F, nominal relative humidity of 60%. No direct exposure to weather. Only relevant to the Control Room envelope (includes Computer and Cable Spreading Rooms) and 13.8K VAC Building.
Indoor - No Air Conditioning	Moist air, average temperature 85°F with winter to summer variation of 70°F - 120°F, maximum relative humidity 100%. No direct exposure to weather. Environment may be climate controlled (heating and/or cooling) which may not prevent local condensation.
Indoor - Wetted	Indoor air, but typically wetted with condensation. Primarily used in the ventilation coolers.
Outdoor	Moist air, temperature -30°F - 110°F, maximum relative humidity 100%. Exposed to weather, including precipitation and wind.
Raw Water (Submerged)	Intermittently wetted on a continual basis or submerged in raw water (i.e., fresh water from lake).
Treated Water - Borated, T<140°F	Exposed to borated water less than 140°F. Borated water chemistry is monitored and controlled in accordance with the requirements of the PBNP Water Chemistry Control Program.

Figure 3.0-1 Table 1 -
Table 3.x.1, Summary of Aging Management Evaluations in Chapter _____ of NUREG-1801 for ____________

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.x.1-01					
3.x.1-02					
3.x.1-03					
3.x.1-04					
3.x.1-05					
3.x.1-06					

Figure 3.0-2 Table 2 -
Table 3.x.2-y, Section 3 Title - Plant Specific System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes

Section 3.0 References

1. D. Peckner and I.M. Bernstein, Handbook of Stainless Steels, McGraw Hill, 1977.
2. A.J. Sedricks, Corrosion of Stainless Steels, John Wiley & Sons, 1979, pp. 152-156.
3. EPRI Report No. NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” Electric Power Research Institute, April 1988.

3.1 Aging Management of Reactor Coolant System

Applicability of Westinghouse WCAP-14575-A for PBNP Class 1 Piping

Westinghouse performed a generic aging management evaluation of Class 1 Piping and Associated Pressure Boundary Components for the Westinghouse Owners Group. This evaluation is documented in the Westinghouse Generic Topical Report (GTR) “Aging Management Review for Class 1 Piping and Associated Pressure Boundary Components”, WCAP-14575-A (Reference 1). This GTR has been accepted by the U.S. NRC for use as a reference in license renewal applications. The PBNP Class 1 Piping and Associated Pressure Boundary Components are specifically included in the Westinghouse GTR, WCAP-14575-A. The Applicant Action Items required by the NRC final safety evaluation report on this GTR, are discussed in Table 3.1.0-1.

The genesis of PBNP was via a “turnkey” project. As such, Westinghouse had direct responsibility for the design, procurement, component fabrication, and construction of PBNP Units 1 and 2. A comparison of PBNP Class 1 Piping and Associated Pressure Boundary Components with the piping and components covered in the WCAP was performed. The design criteria and features, materials of construction, fabrication techniques, installed configurations, modes of operation, and environment/exposures were evaluated and found to be in harmony with the GTR.

The conclusions with respect to aging effects identified in the WCAP, are consistent with the aging effects identified at PBNP, with the following exceptions:

> Material loss caused by wear is not considered to be a credible aging effect because the Class 1 Piping/Components are not exposed to conditions that generate these effects, and it has not been observed to date. Loss of material due to general, pitting and crevice corrosion, cracking due to SCC, and loss of mechanical closure integrity due to aggressive chemical attack are additional aging effects that are considered to require management in the license renewal term.

The required aging management programs for the PBNP Class 1 Piping are identified in Section 3.1.2.1.1, and are further described in Appendix B of the LRA. PBNP will be taking one exception to programs identified in the GTR, as noted below:

> The GTR requires that a one time inspection of a small sample of Class 1 piping from 3/4” to less than 4" NPS using volumetric examination techniques be performed to provide evidence that the piping is not experiencing cracking and therefore is capable of maintaining its pressure boundary integrity under CLB design loads.

The fourth interval PBNP Inservice Inspection Program implements risk informed selection criterion for Examination Category B-F, B-J, C-F-1, and C-F-2 piping welds. The Risk Informed Inservice Inspection (RI ISI) Program for Class 1 piping welds includes all Class 1 piping, except for piping 1-inch NPS and smaller. The RI ISI Program inspections of piping welds less than 4-inch NPS will include volumetric examinations, with the exception of socket welded connections. Since no meaningful volumetric inspection technique exists for the geometry presented by socket welds, a surface examination will be performed.

Implementation of the RI ISI Program during the last inspection interval of the current license period will provide 10 years of volumetric inspection data/information on high and medium risk small bore piping locations greater than 1-inch NPS. Since small bore piping will receive volumetric inspections through the RI ISI Program, there is no need for a one-time special inspection of small bore piping to ensure that cracking is not occurring.

In summary, the Class 1 Piping GTR applies to the Point Beach Nuclear Plant Class 1 Piping, with the exception of the items noted above.

Applicability of Westinghouse WCAP-14577, Rev. 1-A to Point Beach Reactor Vessel Internals

The Westinghouse Owner's Group (WOG) submitted Topical Report, WCAP-14577, “License Renewal Evaluation: Aging Management for Reactor Internals” to the NRC in September 1997 for review and approval. The report provided a technical evaluation of the effects of aging of the Reactor Vessel Internals (RVI) and generically demonstrated how aging management options maintain the intended functions of the RVI and how these options would remain effective during the period of extended operation. The NRC found the generic topical report (GTR) acceptable, as documented in a final safety evaluation report (FSER) transmitted to the WOG in February 2001. Responses to the plant-specific applicant action items listed in the WCAP-14577 Rev. 1-A (Reference 2), are provided in Section 3.1.0-2.

The Point Beach RVIs were included in the Westinghouse Nuclear Steam Supply System (NSSS) scope of supply and were designed, fabricated and installed in accordance with Westinghouse Equipment Specifications. Therefore, the Point Beach RVI components were designed, fabricated and installed to a configuration similar to that specified in the GTR. The design parameters associated with the Point Beach RVI components and the operational environment are bounded by those that are considered in the GTR. The Point Beach RVI components requiring aging management reviews perform the same intended functions as those in the GTR.

The results and conclusions in the GTR with respect to aging mechanisms and effects are applicable to the PBNP RVIs that need to be managed in period of extended operation.

The GTR identifies fatigue as the only aging mechanism related to the RVIs that satisfies the TLAA criteria in 10 CFR 54. However, not all RVI components are sensitive to fatigue. This TLAA is applicable to the PBNP RVIs, and is discussed in Section 4.3 of the LRA.

Aging management program elements are identified in the GTR. Specific Point Beach program details to manage the aging mechanisms and effects are identified in Section 3.1.2.1.3, and are further described in Appendix B of the LRA. These Point Beach specific programs also satisfy the program elements that are identified in the GTR, with the exception of loose parts monitoring, and neutron noise monitoring. Although Point Beach utilizes on-line loose parts monitoring, and on-demand neutron noise monitoring, these techniques are not being credited for aging management.

In summary, the Reactor Vessel Internals GTR applies to the Point Beach Nuclear Plant RVIs, with the exception of the items noted above.

Applicability of Westinghouse WCAP-14574-A to Point Beach Pressurizers

The Westinghouse Generic Topical Report (GTR) for pressurizers, WCAP-14574-A (Reference 3), has been accepted by the NRC for use as a reference in license renewal applications. The Point Beach Nuclear Plant pressurizers are the 84 Series 1000 ft^3 vessels described in the GTR. 84 designates the nominal inside diameter of the pressurizer in inches, and 1000 ft^3 is the pressurizer internal volume. The values of design pressure, design temperature, heater power, and heater quantity for the Point Beach pressurizers correspond to the values of these parameters in the GTR. The materials of the Point Beach pressurizers correspond to those in the GTR with the exception of the shell. The Point Beach pressurizer shells are made of ASTM A-302 Grade B rather than SA 533 grade A Class 2 specified in the GTR. This does not constitute a significant deviation because these materials are essentially the same.

Based on the Westinghouse Equipment Specifications for the Point Beach pressurizers, fabrication techniques and installed configuration are the same as those specified in the GTR with the exception of seismic lugs and valve support bracket lugs. These items were deleted on the Point Beach pressurizers as documented in an addendum to the specification.

The design parameters associated with the containment internal environment at Point Beach fit within the envelope of the values used in the GTR for pressurizer external environment.

The parts of the Point Beach pressurizers that were determined to require an aging management review and their intended functions are the same as those in the pressurizer GTR.

The GTR identifies SCC of pressurizer sensitized stainless steel nozzle safe ends as a potential aging mechanism. However, the GTR recognizes that service experience with nozzles and safe ends in Westinghouse pressurizers has been excellent and bases the need for aging management on general industry concerns. The GTR identifies ASME Section XI inspections as the program to manage SCC of the safe ends. Consistent with the other Class 1 AMRs, SCC of stainless steel materials in the primary coolant environment can be effectively managed by the Water Chemistry Control Program. Cracking due to flaw growth is considered and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is credited to manage the aging effects. As such, ASME Section XI inspections remain as an aging management program for the pressurizer nozzle safe-ends.

For the support skirt weld, ASME Section XI Subsection IWB, Figure IWB-2500-14 is applicable, and identifies the area of interest for examination as “t” which is equal to the thickness of the pressure retaining component “t” or wall thickness. The support skirt-to-lower head weld on the PBNP pressurizers is outside this area of interest, therefore, no IWB examination is required. This weld is examined in accordance with ASME Section XI Subsection IWF.

The discussion and evaluation of Time Limited Aging Analyses (TLAA's) in the pressurizer GTR is general in nature and is not intended to satisfy plant specific identification and disposition of pressurizer TLAA's. The GTR identifies fatigue as the only TLAA generically applicable to Westinghouse pressurizers. The GTR then provides a discussion on options for dispositioning and management of fatigue for pressurizers. The PBNP TLAA identification effort for Point Beach also identified fatigue as the only TLAA applicable to the pressurizers. In summary, the pressurizer GTR applies to the Point Beach Nuclear plant pressurizers with the exception of the items noted above.

A reconciliation of the final SER for WCAP-14574-A applicant action items is provided in Table 3.1.0-3.

3.1.1 Introduction

This section provides the results of the aging management review for those components identified in Section 2.3.1, Reactor Vessel, Internals, and Reactor Coolant System, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section, are described in the indicated sections.

- Class 1 Piping/Components System (Section 2.3.1.1)
- Reactor Vessel (Section 2.3.1.2)
- Reactor Vessel Internals (Section 2.3.1.3)
- Pressurizer (Section 2.3.1.4)
- Steam Generators (Section 2.3.1.5)
- Non-Class 1 RCS Components System (Section 2.3.1.6)

Table 3.1.1, Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System, provides the summary of the programs evaluated in NUREG-1801 for the Reactor Coolant System component groups that are relied on for license renewal.

This table uses the format described in Section 3.0 above. Note that this table only includes those component groups that are applicable to a PWR.

3.1.2 Results

The following tables summarize the results of the aging management review for systems in the Reactor Vessel, Internals, and Reactor Coolant System group:

Table 3.1.2-1, Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Table 3.1.2-2, Reactor Coolant System - Reactor Vessel - Summary of Aging Management Evaluation

Table 3.1.2-3, Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Table 3.1.2-4, Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Table 3.1.2-5, Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Table 3.1.2-6, Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

The materials that specific components are fabricated from, the environments to which components are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above systems in the following subsections of Section 3.1.2.1, Materials, Environment, Aging Effects Requiring Management and Aging Management Programs:

Section 3.1.2.1.1, Class 1 Piping/Components System

Section 3.1.2.1.2, Reactor Vessel

Section 3.1.2.1.3, Reactor Vessel Internals

Section 3.1.2.1.4, Pressurizer

Section 3.1.2.1.5, Steam Generators

Section 3.1.2.1.6, Non-Class 1 RCS Components System

3.1.2.1 Materials, Environment, Aging Effects Requiring Management and Aging Management Programs

3.1.2.1.1 Class 1 Piping/Components System

Materials

The materials of construction for the Class 1 Piping/Components System are:

- Carbon Steel (strongback only)
- Cast Stainless Steel
- Low Alloy Steel
- Stainless Steel
- Wrought Stainless Steel
- Alloy 690 (Unit 2 only)
- 82/152 Weld Material (Unit 2 only)

Environment

The Class 1 Piping/Components System is exposed to the following environments:

- Borated Water Leaks (External)
- Containment (External)
- Treated Water - Other (Internal)
- Treated Water - Primary, 140°F<T<480°F (Internal)
- Treated Water - Primary, T>480°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Class 1 Piping/Components System, require management:

- Cracking due to Flaw Growth

- Cracking due to SCC
- Erosion
- Loss of Material due to Corrosion
- Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack
- Loss of Mechanical Closure Integrity due to Stress Relaxation
- Reduction in Fracture Toughness due to Thermal Embrittlement

Aging Management Programs

The following aging management programs manage the aging effects for the Class 1 Piping/Components System:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Reactor Coolant System Alloy 600 Inspection Program
- Water Chemistry Control Program

3.1.2.1.2 Reactor Vessel

Materials

The materials of construction for the Reactor Vessel are:

- Alloy 600
- Carbon Steel
- Low Alloy Steel
- Low Alloy Steel w/ Stainless Steel Cladding
- Stainless Steel
- Stainless Steel Weld Butter

Environment

The Reactor Vessel components are exposed to the following environments:

- Borated Water Leaks (External)
- Containment (External)

- Treated Water - Primary, T>480°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Reactor Vessel, require management:

- Cracking due to Flaw Growth
- Cracking due to SCC
- Loss of Material due to Boric Acid Corrosion
- Loss of Material due to Corrosion
- Loss of Material due to Wear
- Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack
- Loss of Mechanical Closure Integrity due to Stress Relaxation
- Reduction in Fracture Toughness due to Irradiation Embrittlement

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Vessel components:

- Reactor Coolant System Alloy 600 Inspection Program
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Corrosion Program
- Reactor Vessel Surveillance Program
- Water Chemistry Control Program

3.1.2.1.3 Reactor Vessel Internals

Materials

The materials of construction for the Reactor Vessel Internals are:

- ACI CF-8 Type 304
- ASTM A182 Type 304
- ASTM A213 Type 304
- ASTM A240 Type 304
- ASTM A240 Type 304, with #6 Hayes Stellite coating
- ASTM A249 Type 304

- ASTM A269 Type 304
- ASTM A276 Type 304
- ASTM A296, CF-8
- ASTM A298 (weld material)
- ASTM A312 Type 304
- ASTM A351 CF-8
- ASTM B166 (Inconel 600)
- ASTM B166 (Inconel 600) with #6 Hayes Stellite coating
- Inconel X-750
- Stainless Steel (Unspecified)
- Type 347, 316 or 304 SS (Unspecified)
- W PDS-70041-EJ (Inconel X-750)
- W PS 10725-HA Rev C, AISI 403

Environment

The Reactor Vessel Internals components are exposed to the following environments:

- Treated Water - Primary, T>480°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Reactor Vessel Internals, require management:

- Cracking
- Dimensional Change
- Loss of Material
- Loss of Preload
- Reduction in fracture toughness

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Vessel Internals components:

- Reactor Vessel Internals Program

- Thimble Tube Inspection Program
- Water Chemistry Control Program

3.1.2.1.4 Pressurizer

Materials

The materials of construction for the Pressurizer are:

- Alloy Steel
- Alloy Steel w/ Stainless Steel Cladding
- Carbon Steel
- Carbon Steel w/ Stainless Steel Cladding
- Carbon Steel w/ Stainless Steel Disc Insert
- Low Alloy Steel
- Stainless Steel

Environment

The Pressurizer components are exposed to the following environments:

- Borated Water Leaks (External)
- Containment (External)
- Treated Water - Primary, T>480°F (Internal) (includes steam space)

Aging Effects Requiring Management

The following aging effects, associated with the Pressurizer, require management:

- Cracking due to Flaw Growth
- Cracking due to SCC
- Loss of Material
- Loss of Material due to Aggressive Chemical Attack
- Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack
- Loss of Mechanical Closure Integrity due to Stress Relaxation

Aging Management Programs

The following aging management programs manage the aging effects for the Pressurizer components:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Bolting Integrity Program
- Boric Acid Corrosion Program
- Water Chemistry Control Program

3.1.2.1.5 Steam Generators

Materials

The materials of construction for the Steam Generators are:

- Alloy 600
- Alloy 600 Clad
- Alloy 600 TT
- Alloy 690
- Alloy 690 Clad
- Alloy 690 TT
- Alloy Steel
- Carbon Steel
- Carbon Steel with SS Clad
- Carbon Steel with SS Disc Insert
- Chrome-Plated Alloy 600
- Low Alloy Steel
- Stainless Steel
- Stainless Steel Weld Butter

Environment

The Steam Generators are exposed to the following environments:

- Borated Water Leaks (External)
- Containment (External)
- Treated Water - Primary, T>480°F (Internal)

- Treated Water - Secondary, T>120°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Steam Generators, require management:

- Cracking due to Flaw Growth
- Cracking due to IGA/IGSCC
- Cracking due to PWSCC
- Cracking due to SCC
- Fatigue Cracking
- Loss of Material
- Loss of Material due to Aggressive Chemical Attack
- Loss of Material due to FAC
- Loss of Material due to Pitting
- Loss of Material due to Wear
- Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack
- Loss of Mechanical Closure Integrity due to Stress Relaxation

Aging Management Programs

The following aging management programs manage the aging effects for the Steam Generators components:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Bolting Integrity Program
- Boric Acid Corrosion Program
- Flow-Accelerated Corrosion Program
- Periodic Surveillance and Preventive Maintenance Program
- Steam Generator Integrity Program
- Water Chemistry Control Program

3.1.2.1.6 Non-Class 1 RCS Components System

Materials

The materials of construction for the Non-Class 1 RCS Components System are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Copper Alloy (Zn <15%)
- Copper Alloy (Zn >15%)
- Stainless Steel

Environment

The Non-Class 1 RCS Components System is exposed to the following environments:

- Air and Gas (Internal)
- Air and Gas - Wetted, T<140°F (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Oil and Fuel Oil (Internal)
- Treated Water - Borated, T<140°F (Internal)
- Treated Water - Other (Internal)
- Treated Water - Other (Stagnant) (Internal)
- Treated Water - Primary, T<140°F (Internal)
- Treated Water - Primary, T>480°F (Internal)
- Treated Water - Primary, 140°F<T<480°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Non-Class 1 RCS Components System, require management:

- Cracking due to IGA/IGSCC
- Cracking due to SCC
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Non-Class 1 RCS Components System:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.1.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

NUREG-1801 Volume 1 Tables provide the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Reactor Vessel, Internals, and Reactor Coolant System, those programs are addressed in the following sections.

3.1.2.2.1 Cumulative Fatigue Damage

Fatigue is a 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 separately in Section 4.3. Secondary-side steam generator pressure boundary components are included in this grouping although they are not part of the reactor coolant pressure boundary.

3.1.2.2.2.1 Loss of Material due to Pitting and Crevice Corrosion

Aging effects on the steam generator secondary-side internal surfaces are effectively managed by control of secondary-side water chemistry through the Water Chemistry Control Program and inservice inspections performed in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. To augment these programs, PBNP utilizes the Steam Generator Integrity Program which provides all-inclusive guidance for the management of steam generator assets.

3.1.2.2.2.2 Loss of Material due to Pitting and Crevice Corrosion

Applicable to BWR Only

3.1.2.2.3.1 **Loss of Fracture Toughness due to Neutron Irradiation Embrittlement**

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). The evaluation of this TLAA is addressed separately in Section 4.2.

3.1.2.2.3.2 **Loss of Fracture Toughness due to Neutron Irradiation Embrittlement**

Loss of fracture toughness in reactor vessel beltline shell and weld materials due to neutron irradiation embrittlement has been identified as an aging effect requiring management during the period of extended operation. The upper shell and nozzles are not subject to significant neutron irradiation exposure because of their physical distance from the reactor core. The limiting beltline material is the PBNP U2 reactor vessel at the intermediate-to-lower shell beltline circumferential weld. The PBNP Reactor Vessel Surveillance Program, in conjunction with TLAA analyses, effectively manages loss of fracture toughness in the beltline materials. The Reactor Vessel Surveillance Program provides adequate material property and neutron dosimetry data to predict fracture toughness in beltline materials at the end of the period of extended operation. In addition, equivalent margins analyses have been performed in accordance with 10 CFR 50 Appendix G methods. These fracture mechanics analyses (see TLAAs, Section 4.4) provide assurance that beltline material toughness values in the PBNP reactor vessels will remain at acceptable levels through the period of extended operation. The PBNP surveillance capsule withdrawal schedule is described in Section 4.2.

3.1.2.2.3.3 **Loss of Fracture Toughness due to Neutron Irradiation Embrittlement**

Loss of fracture toughness due to neutron irradiation embrittlement was identified as an aging effect requiring management for the PBNP baffle/former bolts. The Reactor Vessel Internals Program will be used to manage this aging effect.

During the 1998 refueling outage, the entire population of 728 Type 347 stainless steel baffle/former bolts was selected for inspection by UT at Point Beach Unit 2. A total of 175 bolts were replaced with Type 316 stainless steel bolts during the outage. These bolts were part of a pre-qualified minimum bolt pattern for PBNP. The Westinghouse Owners Group developed an NRC-approved methodology (WCAP-15029-P-A (Reference 4)) to determine number and distribution of intact and functional baffle bolts required to ensure safe plant operation. Plant specific applications of the Westinghouse methodology were performed in support of the inspection and replacement programs at Point Beach Unit 2.

Maintaining the structural integrity of the bolts within this pattern assures compliance with requirements of ASME III, Subsection NG (1989), considering dynamic loads generated by a 10" line break in the reactor coolant system. This LOCA load bounds those that are generated by effects of earthquake, thermal, deadweight, and flow-induced vibration. No further inspections of baffle/former or barrel/former bolts are warranted for Unit 2 in view of this inspection and replacement. Point Beach will continue to monitor and participate in industry initiatives with regard to baffle/former and barrel/former bolt performance to support aging management for the Unit 1 bolting.

Transmission Electron Microscopy studies of thin foils prepared from an intact baffle/former bolt and locking device removed from the Point Beach Unit 2 RVI in 1999 indicate that voids were present in the threaded end of the bolt but not in the head or the 304 SS locking device. The maximum void volume observed in the 347 SS bolt material, 0.03%, is small and preliminary extrapolation to the end of extended life using a simple square law suggest that void swelling should not be a concern. Point Beach is also participating in industry initiatives to determine the extent of the concerns associated with void swelling and what appropriate changes to the Point Beach Reactor Vessel Internals Program may be required once an industry position has been established.

3.1.2.2.4.1 Crack Initiation and Growth due to Thermal and Mechanical Loading or Stress Corrosion Cracking

Crack initiation and growth due to SCC was identified as an aging effect requiring management in small-bore (<NPS 4) reactor coolant system piping and branch lines. Aging management of service-induced cracking will be accomplished by a combination of the Water Chemistry Control Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. PBNP has implemented a Risk Informed ISI program, and as part of this transition, some small bore (<NPS 4) RCS locations were identified for inspection. These inspections of small bore RCS piping will meet the intent of the one-time inspections referenced in NUREG-1800.

The proposed combination the Water Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program is an effective means of managing service-induced cracking in small-bore reactor coolant system piping and connected branch lines during the period of extended operation.

3.1.2.2.4.2 Crack Initiation and Growth due to Thermal and Mechanical Loading or Stress Corrosion Cracking

Applicable to BWR Only

3.1.2.2.4.3 Crack Initiation and Growth due to Thermal and Mechanical Loading or Stress Corrosion Cracking

Applicable to BWR Only

3.1.2.2.5 Crack Growth due to Cyclic Loading

Underclad cracking in carbon/low-alloy steel which has been clad with austenitic stainless steel using weld-overlay processes has been identified as an aging effect requiring management and is addressed as a TLAA. An evaluation of the TLAA for underclad cracking is contained in Section 4.4.

3.1.2.2.6 Changes in Dimension due to Void Swelling

The NRC's concern is that VT-3 inspection is not sufficient to detect this aging effect. Recent destructive examinations of baffle/former bolts removed from the PBNP reactor vessel internals suggest that void volumes are very small and changes in dimension in baffle/former bolts due to void swelling should not be a concern during the period of extended operation. Transmission Electron Microscopy studies of thin foils prepared from an intact baffle/former bolt and locking device removed from the Point Beach Unit 2 RVI in 1999 indicate that voids were present in the threaded end of the bolt but not in the head or the 304 SS locking device. The maximum void volume observed in the 347 SS bolt material, 0.03%, is small and preliminary extrapolation to the end of extended life using a simple square law suggest that void swelling should not be a concern.

However, the Reactor Vessel Internals Program is credited to manage changes in dimension due to void swelling. PBNP will continue to participate in industry investigations of aging effects applicable to reactor vessel internals. PBNP will incorporate applicable results of industry initiatives related to void swelling in the Reactor Vessel Internals Program.

3.1.2.2.7.1 Crack Initiation and Growth due to Stress Corrosion Cracking or Primary Water Stress Corrosion Cracking

The core support pads and the bottom head instrument penetrations are fabricated from Alloy 600. Crack initiation and growth of the bottom head penetrations due to SCC/PWSCC is managed at PBNP by a combination of the Water Chemistry Control Program and the Reactor Coolant System Alloy 600 Inspection Program. The RCS Alloy 600 Inspection Program is a plant-specific program which includes participation in industry initiatives related to management of Alloy 600 penetration cracking issues. The core support pads are susceptible to crack initiation and growth due to SCC/PWSCC and are managed at PBNP by a combination of the Water Chemistry Control Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The reactor vessel leak detection line is outside the primary pressure boundary, and is therefore not in-scope. The pressurizer spray head performs no license renewal intended function at PBNP, including Appendix R considerations (the pressurizer cooldown rate required for an Appendix R scenario is achievable without a functioning spray head). The steam generator instrument nozzles are low-alloy steel, not Alloy 600 or stainless steel, and therefore are not included in this component group.

3.1.2.2.7.2 Crack Initiation and Growth due to Stress Corrosion Cracking or Primary Water Stress Corrosion Cracking

The PBNP primary loop elbows are CASS material and are subject to these aging effects. The PBNP Water Chemistry Control Program monitors and controls primary water chemistry in accordance with the guidelines of EPRI TR-105714 and therefore effectively manages crack initiation and growth due to SCC. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is also credited to verify the effectiveness of water chemistry control.

3.1.2.2.7.3 Crack Initiation and Growth due to Stress Corrosion Cracking or Primary Water Stress Corrosion Cracking

There are no components fabricated from Alloy 600 in the PBNP pressurizer, and therefore this line item was not used. Instrument penetrations, heater well tubes, and adapters are stainless steel.

3.1.2.2.8 Crack Initiation and Growth due to Stress Corrosion Cracking or Irradiation-Assisted Stress Corrosion Cracking

Crack initiation and growth due to SCC and IASCC were identified as aging effects requiring management for PBNP baffle/former bolts. A combination of the Water Chemistry Control Program and the Reactor Vessel Internals Program is used to manage this aging effect.

During the 1998 refueling outage, the entire population of 728 Type 347 stainless steel baffle/former bolts was selected for inspection by UT at Point Beach Unit 2. A total of 175 bolts were replaced with Type 316 stainless steel bolts during the outage. These bolts were part of a pre-qualified minimum bolt pattern for PBNP. The Westinghouse Owners Group developed a an NRC-approved methodology (WCAP-15029-P-A, (Reference 4)) to determine number and distribution of intact and functional baffle bolts required to ensure safe plant operation. Plant specific applications of the Westinghouse methodology were performed in support of the inspection and replacement programs at Point Beach Unit 2.

Maintaining the structural integrity of the bolts within this pattern assures compliance with requirements of ASME III, Subsection NG (1989), considering dynamic loads generated by a 10" line break in the reactor coolant system. This LOCA load bounds those that are generated by effects of earthquake, thermal, deadweight, and flow-induced vibration. No further inspections of baffle/former or barrel/former bolts are warranted for Unit 2 in view of this inspection and replacement. Point Beach will continue to monitor and participate in industry initiatives with regard to baffle/former and barrel/former bolt performance to support aging management for the Unit 1 bolting. As new information and technology becomes available, the plant-specific Reactor Vessel Internals Program will be modified to incorporate enhanced surveillance techniques.

3.1.2.2.9 Loss of Preload due to Stress Relaxation

Loss of preload due to stress relaxation was identified as an aging effect requiring management for PBNP baffle/former bolts. Loss of preload due to stress relaxation will be managed by the Reactor Vessel Internals Program. PBNP will continue to participate in industry investigations of aging effects applicable to reactor vessel internals as well as initiatives to develop advanced inspection techniques. Aging management activities or surveillance techniques resulting from these initiatives will be incorporated, as required, as enhancements to the Reactor Vessel Internals Program.

3.1.2.2.10 **Loss of Section Thickness due to Erosion**

This component group is not applicable to PBNP. The feedwater delivery to the steam generators at PBNP is through feedrings to J-tubes. The feedrings and J-tubes perform no license renewal intended function.

3.1.2.2.11 **Crack Initiation and Growth due to PWSCC, ODSCC, or Intergranular Attack or Loss of Material due to Wastage and Pitting Corrosion or Loss of Section Thickness due to Fretting and Wear or Denting due to Corrosion of Carbon Steel Tube Support Plate**

Cracking due to PWSCC and IGA/IGSCC and loss of material due to pitting and wear were identified as aging effects requiring management for the PBNP steam generator tubes and plugs. These aging effects will be jointly managed by the Water Chemistry Control Program (both primary and secondary water chemistry) and the Steam Generator Integrity Program. The Steam Generator Integrity Program at PBNP was developed to meet the guidelines in NEI 97-06.

New, replacement recirculating steam generators were installed at PBNP (U1-1984, U2-1996). These new steam generators incorporate many enhancements in design and materials of construction, to minimize these aging effects.

3.1.2.2.12 **Loss of Section Thickness due to Flow-accelerated Corrosion**

Tube support lattice bars are fabricated from either stainless steel or Alloy 600 in the PBNP replacement steam generators. These materials are not susceptible to FAC. However, these materials are susceptible to cracking, which is managed by the Water Chemistry Control Program, and augmented by the Steam Generator Integrity Program, which provides for secondary side inspections to verify the effectiveness of water chemistry control.

3.1.2.2.13 **Ligament Cracking due to Corrosion**

There are no carbon steel tube support materials in the PBNP steam generators. However, cracking due to SCC was identified as the aging effect requiring management for the stainless steel tube support plates in the PBNP steam generators. This aging effect is managed by the Water

Chemistry Control Program, and augmented by the Steam Generator Integrity Program, which provides for secondary side inspections to verify the effectiveness of water chemistry control.

3.1.2.2.14 Loss of Material due to Flow-accelerated Corrosion

Applicable to PWR (CE) only.

3.1.2.3 Time-Limited Aging Analysis

The time-limited aging analyses (TLAA) identified below are associated with the Reactor Vessel, Internals, and Reactor Coolant System components. The section of the LRA that contains the TLAA review results is indicated in parenthesis.

- Embrittlement (Section 4.2, Reactor Vessel Radiation Embrittlement)
- Fatigue (Section 4.3, Metal Fatigue)
- Leak-Before-Break (Section 4.4.4, Leak-Before-Break)
- Environmental Qualification (Section 4.8, Environmental Qualification)

3.1.3 Conclusion

The Reactor Vessel, Internals, and Reactor Coolant System piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Reactor Vessel, Internals, and Reactor Coolant System components are identified in the summaries in Section 3.1.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Vessel, Internals, and Reactor Coolant System components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.1.0-1 Class 1 Piping and Associated Pressure Boundary Components - WCAP-14575-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(1) The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor coolant system piping. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this topical report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor coolant system piping and associated pressure boundary components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	As summarized in Section 3.1 of the LRA, the Class 1 piping and associated pressure boundary components are bounded by the topical report with regard to design criteria and features, materials of construction, fabrication techniques, installed configuration, modes of operation, and environments/exposures. Deviations from the aging management programs included in the topical report are also described in Section 3.1 of the LRA. Programs necessary to manage the effects of aging are identified in Section 3.1.2.1.1, and are summarized in Appendix B of the LRA. Program commitments to manage the effects of aging for Class 1 piping and associated pressure boundary components are also described in Appendix B of the LRA.
(2) Summary description of the programs and evaluation of Time-Limited Aging Analyses are to be provided in the license renewal FSAR supplement in accordance with 10 CFR 54.21(d).	A summary of the programs identified to manage the effects of aging for Class 1 piping and associated pressure boundary components is included in the proposed FSAR supplement in Appendix A of the LRA. A mark-up of the FSAR sections affected by the TLAA evaluations is also included in Appendix A of the LRA
(3) The renewal applicant should complete the updated review of generic communications and capture any additional items not identified by the original review.	PBNP has completed an updated review of generic communications for applicability to Class 1 piping and associated pressure boundary components. All generic communications applicable to aging effects have been captured.

Table 3.1.0-1 Class 1 Piping and Associated Pressure Boundary Components - WCAP-14575-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(4) The license renewal applicant must provide a description of all insulation used on austenitic stainless steel NSSS piping to ensure the piping is not susceptible to stress-corrosion cracking from halogens.	During construction, the Class 1 piping was insulated in accordance with the applicable Westinghouse Equipment Specification. The specification listed specific tradenames that were approved, by Westinghouse, for use on austenitic stainless steel. As described in the FSAR, Section 4.2, "…external corrosion resistant surfaces in the reactor coolant system are insulated with low halide or halide free insulating material…" Subsequent insulation work activities were done in accordance with PBNP specification(s), which impose the requirements of NRC Regulatory Guide 1.36. Since all the insulation that was used on Class 1 piping and associated pressure boundary components is low halide, or halide free, the piping is not susceptible to stress corrosion cracking initiated by such halides.
(5) The license renewal applicant should describe how each plant-specific AMP addresses the following 10 elements: (1) scope of the program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	Programs necessary to manage the effects of aging for Class 1 piping and associated pressure boundary components address the 10 elements identified. The 10 elements are evaluated in detail in Appendix B of the LRA.

Table 3.1.0-1 Class 1 Piping and Associated Pressure Boundary Components - WCAP-14575-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(6) The license renewal applicant should perform additional inspection of small-bore Reactor Coolant System piping, that is, less than 4-inch-size piping, for license renewal to provide assurance that potential cracking of small-bore Reactor Coolant System piping is adequately managed during the period of extended operation.	The fourth interval PBNP Inservice Inspection Program implements risk informed selection criterion for Class 1 piping welds. The Risk Informed Inservice Inspection (RI ISI) Program for Class 1 piping welds includes all Class 1 piping, except for piping 1-inch NPS and smaller. The RI ISI Program inspections of piping welds less than 4-inch NPS will include volumetric examinations, with the exception of socket welded connections. Until a meaningful volumetric inspection technique is created for the geometry presented by socket welds, a surface examination will be substituted. Implementation of the RI ISI Program during the last inspection interval of the current license period will provide 10 years of volumetric inspection data on high and medium risk small bore piping locations greater than 1-inch NPS. Since small bore piping will receive volumetric inspections through the RI ISI Program, there is no need for a one-time special inspection of small bore piping to ensure that cracking is not occurring.
(7) Components that have delta ferrite levels below the susceptibility screening criteria have adequate fracture toughness and do not require supplemental inspection. As a result of thermal embrittlement, components that have delta ferrite levels exceeding the screening criterion may not have adequate fracture toughness and do require additional evaluation or examination. The license renewal applicant should address thermal-aging issues in accordance with the staff's comments in Section 3.3.3 of this evaluation.	The aging management review methodology identifies reduction in fracture toughness as the aging effect related to thermal aging. Reduction in fracture toughness for Class 1 piping and associated pressure boundary components is addressed in Section 3.1.2.1.1 and Table 3.1.2-1 of the LRA. The methodology is consistent with the staff's comments. In addition, fracture mechanics evaluations were performed to take loss of fracture toughness for CASS components into consideration for the period of extended operation. These TLLAA evaluations are discussed in Section 4.4.3 and Section 4.4.4 of the LRA

Table 3.1.0-1 Class 1 Piping and Associated Pressure Boundary Components - WCAP-14575-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(8) The license renewal applicant should perform additional fatigue evaluations or propose an AMP to address the components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575.	PBNP has performed a plant-specific fatigue evaluation for Class 1 piping and reactor coolant pumps. These evaluations are described in Section 4.3 of the LRA.
(9) The staff recommendation for the closure of GSI-190 “Fatigue Evaluation of Metal Components for 60-Year Plant Life” is contained in a December 26, 1999, memorandum from Ashok Thadani to William Travers. The license renewal applicant should address the effects of the coolant environment on component fatigue life as aging management programs are formulated in support of license renewal. The evaluation of a sample of components with high-fatigue usage factors using the latest available environmental fatigue data is an acceptable method to address the effects of the coolant environment on component fatigue life.	PBNP has performed a plant-specific evaluation of a sample of Class 1 piping and associated pressure boundary components with regard to the environmental effects on fatigue (EAF). The sample consisted of the PBNP equivalent NUREG/CR-6260 locations. The calculated environmental fatigue usage factors were acceptable for a 60-year operating period. See Section 4.3.10 of the LRA.

Table 3.1.0-1 Class 1 Piping and Associated Pressure Boundary Components - WCAP-14575-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(10) The license renewal applicant should revise AMP-3.6 to include an assessment of the margin on loads in conformance with the staff guidance provided in Reference 11. In addition, AMP-3.6 should be revised to indicate If the CASS component is repaired or replaced per ASME Code, Section XI IWB4000 or IWB7000, a new LBB analysis based on the material properties of the repaired or replaced component (and accounting for its thermal aging through the period of extended operation, as appropriate), is required to confirm the applicability of LBB. The inservice examination/flaw evaluation option is, per the basis on which the NRC staff has approved LBB in the past, insufficient to reestablish LBB approval.	The original PBNP Leak-Before-Break (LBB) analysis for the main loop piping was performed generically by Westinghouse, and approved by the NRC as communicated in NRC Generic Letter 84-04. Subsequently, the LBB analysis was revised addressing SG replacement, power uprate, and a 60-year operating period. The revised LBB analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. The revised LBB analysis utilizes a methodology consistent with the original LBB analysis. (See Section 4.4.4 of the LRA for details) In addition, LBB analyses were performed for the RHR, accumulator injection, and surge line piping. These LBB analyses include the effects of power uprate, and a 60-year operating period. These analyses are also consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. (See Section 4.4.5, Section 4.4.6, and Section 4.4.7 of the LRA for details.) Plant process control procedures (design control, repair / replacement, and welding) will be revised to ensure that repair or replacement of Class 1 piping components (welded connections or CASS) would require a new LBB analysis based on replacement process and / or material properties.

Table 3.1.0-2 Reactor Vessel Internals - WCAP-14577, Rev. 1-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(1) To ensure applicability of the results and conclusions of WCAP-14577 to the applicant's plant(s), the license renewal applicant is to verify that the critical parameters for the plant are bounded by the topical report. Further, the renewal applicant must commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. Applicants for license renewal will be responsible for describing any such commitments and proposing the appropriate regulatory controls. Any deviations from the aging management programs described in this topical report as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel internal components or other information presented in the report, such as materials of construction, must be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The Point Beach reactor vessel internals are bounded by WCAP-14577 Rev. 1-A, with respect to design criteria and features, material of construction, fabrication techniques, installed configuration, mode of operation and environments/exposures. Programs necessary to manage the effects of aging have been identified in Section 3.1.2.1.3, and are summarized in Appendix B of the LRA. These programs meet the guidance of WCAP-14577 Rev. 1-A, with the exception of crediting loose parts monitoring and neutron noise monitoring surveillance techniques for managing irradiation-assisted stress-corrosion cracking, stress relaxation, wear, and fatigue of RVI components. Although PBNP performs these surveillance techniques, they are not being credited since the results are not conclusive. PBNP relies on the rigor of its RVI inspection activities coupled with monitoring industry initiatives under the EPRI MRP. PBNP will implement the NRC approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort.

Table 3.1.0-2 Reactor Vessel Internals - WCAP-14577, Rev. 1-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(2) A summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs must be provided in the license renewal FSAR supplement in accordance with 10 CFR 54.21(d).	Programs necessary to manage the effects of aging for the Point Beach reactor vessel internals are the Reactor Vessel Internals Program, the Water Chemistry Control Program, and the Thimble Tube Inspection Program. These programs are described in the FSAR Supplement provided as part of the application. Summary descriptions of these programs are provided in Appendix A and Appendix B of the LRA. The only TLAA applicable to the Point Beach reactor vessel internals is fatigue. This TLAA for metal fatigue has been evaluated and found to be acceptable for the 60 year operating period (see Section 4.3.2 of the LRA). In addition, cycle counting as part of the Fatigue Monitoring Program is credited with confirming the assumptions used in the evaluation are not exceeded.
(3) For the holddown spring, applicants for license renewal are expected to address intended function, aging management review, and appropriate aging management program(s).	The holddown spring is within the scope of license renewal for the Point Beach reactor vessel internals. The intended function, results of the aging management review, and aging management program for the holddown spring have been included in Table 3.1.2-3 of the LRA.

Table 3.1.0-2 Reactor Vessel Internals - WCAP-14577, Rev. 1-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(4) The license renewal applicant must address aging management review, and appropriate aging management program(s), for guide tube support pins	In Section 2.6.7.2 of the GTR, it is stated, “As noted above, pin degradation does not lead to a loss of intended function. Generally, pin replacement is considered to be a sound maintenance practice to preclude degradation when industry experience indicates that such degradation has been observed.” All 33 guide tube support pins (split pins) were replaced at Point Beach Unit 1 during the 1985 Refueling outage; four pins were replaced at Unit 2 during its 1985 outage. The new pins were fabricated using a new Framatome design, which had been installed in French nuclear reactors that had experienced the SCC problem. The original design of the support pin was susceptible to SCC due to an undesirable microstructure caused by solution heat treatment of the pins at a temperature less than 1800 °F after which they were age-hardened and highly stressed. The replacement pins were solution heat-treated at 2000 °F, followed by age-hardening at 1300 °F. Other improvements in machined configuration and surface finish were incorporated in the new design. Final installation torque was reduced to achieve adequate cold preload and still maintain a tight joint. No evidence of cracking of the redesigned guide tube support pins has since been observed at Point Beach. The effects of SCC on reactor vessel internals guide tube support pins fabricated from Alloy X-750 with the updated pin designs may therefore be considered insignificant (GTR 3.1.2.2). The original pins remaining in Unit 2 were verified by material heat records to have been solution heat treated above 1800 degrees F, but the combination of material, design geometry, and installation torque make these pins potentially susceptible to SCC. The Reactor Vessel Internals Program is credited with managing the potential cracking in these split pins due to SCC.

Table 3.1.0-2 Reactor Vessel Internals - WCAP-14577, Rev. 1-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(5) The license renewal applicant must explicitly identify the materials of fabrication of each of the components within the scope of the topical report. The applicable aging effect should be reviewed for each component based on the materials of fabrication and the environment.	The materials of fabrication for the subcomponents of the Point Beach reactor vessel internals within the scope of license renewal have been identified using fabrication drawings and quality records. These materials are explicitly identified in Table 3.1.2-3 of the LRA. The aging effect evaluations are performed based on these materials and the appropriate environment.
(6) The license renewal applicant must describe its aging management plans for loss of fracture toughness in cast austenitic stainless steel RVI components, considering the synergistic effects of thermal aging and neutron irradiation embrittlement in reducing the fracture toughness of these components.	Those reactor vessel internals components at Point Beach within the scope of license renewal, which are fabricated from cast austenitic stainless steel, have been identified. The Reactor Vessel Internals Program is credited with managing the synergistic effects of thermal aging and neutron irradiation embrittlement.

Table 3.1.0-2 Reactor Vessel Internals - WCAP-14577, Rev. 1-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(7) The license renewal applicant must describe its aging management plans for void swelling during the license renewal period.	Recent studies of irradiation-induced swelling and stress relaxation suggest that swelling problems, if they arise in PWR core internals, would be highly localized, occurring in the higher flux and temperature locations. Irradiation-enhanced stress relaxation (or irradiation creep) refers to the accumulation of deformation strain over an extended time period, typically at elevated temperatures. Stress relaxation may mitigate loads resulting from void swelling. Transmission Electron Microscopy studies of thin foils prepared from an intact baffle/former bolt and locking device removed from the Point Beach Unit 2 RVI in 1999 indicate that voids were present in the threaded end of the bolt but not in the head or the 304 SS locking device. The maximum void volume observed in the 347 SS bolt material, 0.03%, is small and preliminary extrapolation to the end of extended life using a simple square law suggest that void swelling should not be a concern. Point Beach is also participating in industry initiatives to determine the extent of the concerns associated with void swelling and what appropriate changes to the Point Beach Reactor Vessel Internals Program may be required once an industry position has been established.
(8) Applicants for license renewal must describe how each plant-specific AMP addresses the following elements: (1) scope of the program, (2) preventative actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	The programs necessary to manage the effects of aging for the Point Beach reactor vessel internals address the 10 elements identified. These elements are described in Appendix B of the LRA.

Table 3.1.0-2 Reactor Vessel Internals - WCAP-14577, Rev. 1-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(9) The license renewal applicant must address plant-specific plans for management of cracking (and loss of fracture toughness) of RVI components, including any plans for augmented inspection activities.	The Point Beach Reactor Vessel Internals Program is credited for managing cracking and loss of fracture toughness of RVI components. This program is described in Appendix B of the LRA.
(10) The license renewal applicant must address plant-specific plans for management of age-related degradation of baffle/former and barrel/former bolting, including any plans for augmented inspection activities.	During the 1999 refueling outage, the entire population of 728 Type 347 stainless steel baffle/former bolts was selected for inspection by UT at Point Beach Unit 2. A total of 175 bolts were replaced with Type 316 stainless steel bolts during the outage. These bolts were part of a pre-qualified minimum bolt pattern for PBNP. The Westinghouse Owners Group developed a an NRC-approved methodology (WCAP-15029-P-A (Reference 4), to determine number and distribution of intact and functional baffle bolts required to ensure safe plant operation. Plant specific applications of the Westinghouse methodology were performed in support of the inspection and replacement programs at Point Beach Unit 2. Maintaining the structural integrity of the bolts within this pattern assures compliance with requirements of ASME III, Subsection NG (1989), considering dynamic loads generated by a 10" line break in the reactor coolant system. This LOCA load bounds those that are generated by effects of earthquake, thermal, deadweight, and flow-induced vibration. No further inspections of baffle/former or barrel/former bolts are warranted for Unit 2 in view of this inspection and replacement. Point Beach will continue to monitor and participate in industry initiatives with regard to baffle/former and barrel/former bolt performance to support aging management for the Unit 1 bolting.

Table 3.1.0-2 Reactor Vessel Internals - WCAP-14577, Rev. 1-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(11) The license renewal applicant must address the TLAA of fatigue on a plant-specific basis	The fatigue TLAA is discussed in Section 4.3 of the LRA. Explicit fatigue analyses have been performed for the Point Beach RV Internals as part of a steam generator replacement/power uprate evaluation using a modified set of design transients expected to bound 60-year plant operation. These analyses results are acceptable for the 60-year operating period.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(1) **3.3.1.1–1 -** License renewal applicants should identify the TLAAs for the pressurizer components, define the associated CUF and, in accordance with 10 CFR 54.21(c)(1), demonstrate that the TLAAs meet the CLB fatigue design criterion, CUF $\leq$1.0, for the extended period of operation, including the insurge/outsurge and other transient loads not included in the CLB which are appropriate to such an extended TLAA, as described in the WOG report “Mitigation and Evaluation of Thermal Transients Caused by Insurges and Outsurges,” MUHP–5060/5061/5062, and considering the effects of the coolant environment on critical fatigue location. The applicant must describe the methodology used for evaluating insurge/outsurge and other off-normal and additional transients in the fatigue TLAAs.	The only TLAA identified for the Point Beach pressurizers is fatigue. Plant specific fatigue evaluations for the pressurizers, including the effect of insurge/outsurge transients, have been performed. The evaluation demonstrates that the cumulative usage factors for pressurizer parts remain $\leq$1.0 for the extended period of operation satisfying the CLB CUF fatigue design criterion. (See Section 4.3.5) The effects of the coolant environment on fatigue have also been specifically analyzed for the Point Beach pressurizers (see Section 4.3.10), and the results are acceptable through the period of extended operation.
(2) **3.2.2.1–1 -** In the report, WOG concluded that general corrosion is nonsignificant for the internal surfaces of Westinghouse-designed pressurizers and that no further evaluations of general corrosion are necessary. While the staff concurs that hydrogen overpressure can mitigate the aggressive corrosive effect of oxygen in creviced geometries on the internal pressurizer surfaces, applicants for license renewal will have to provide a basis (statement) in their plant-specific applications about how their water chemistry control programs will provide for a sufficient level of hydrogen overpressure to manage crevice corrosion of the internal surfaces of their pressurizer.	Hydrogen concentrations in the RCS are strictly maintained within specified limits by measurement of hydrogen concentrations in periodic RCS samples, and adjusting hydrogen overpressure in the volume control tanks accordingly. The hydrogen concentration limits established for the RCS ensure that general corrosion is non-significant for the internal surfaces of the Point Beach pressurizers as well as other Class 1 components. Hydrogen concentration limits for the RCS are delineated in the Water Chemistry Control Program.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(3) **3.2.2.1-2 -** The staff finds that the criteria in GL 88–05 and the Section XI requirements for conducting system leak tests and VT–2 type visual examinations of the pressurizer pressure boundary are acceptable programs for managing boric acid corrosion of the external, ferritic surfaces and components of the pressurizer. However, the report fails to refer to the actual provisions in the ASME Code, Section XI that require mandatory system leak tests of the pressurizer boundary. The applicants must identify the appropriate Code inspection requirements from ASME Code Table IWB-2500-1.	The ASME Section XI, Subsection IWB inspections include Examination Categories B-B, B-D, B-F, B-H, B-G-2, and B-P.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(4) **3.2.2.3.2–1 -** The staff concurs that the potential to develop SCC in the bolting materials will be minimized if the yield strength of the material is held to less than 150 ksi, or the hardness is less than 32 on the Rockwell C hardness scale; however, the staff concludes that conformance with the minimum yield strength criteria in ASME Specification SA–193 Grade B7 does not in itself preclude a quenched and tempered low-alloy steel from developing SCC, especially if the acceptable yield strength is greater than 150 ksi. To take credit for the criteria in EPRI Report NP–5769, the applicant needs to state that the acceptable yield strengths for the quenched and tempered low-alloy steel bolting materials (e.g., SA–193, Grade B7 materials) are in the range of 105–150 ksi.	The potential for SCC of fasteners is minimized by utilizing ASTM A193, Gr. B7 bolting material and limiting contaminants such as chlorides and sulfur in lubricants and sealant compounds. Additionally, sound maintenance bolt torquing practices are used to control bolting material stresses. The use of ASTM A193, Gr. B7 bolting specifies a minimum yield strength of 105 Ksi, which is well below the 150 Ksi threshold value specified in EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” April 1988. Bolting fabricated in accordance with this standard could be expected to have yield strengths less than 150 Ksi. However, since the maximum yield strength is not specified for this bolting material, absolute assurance can not be provided that the yield strength of the bolting would not exceed 150 Ksi. For these cases, the combination of specifying ASTM A193 Gr. B7 bolting material, control of bolt torquing, and control of contaminants will ensure that SCC will not occur. These actions have been effective in eliminating the potential for SCC of bolting materials. The results of reviews of the Point Beach condition report database, Inservice Inspection database, and general documentation database support this conclusion in that no instances of pressure boundary bolting degradation due to SCC were identified. Therefore, cracking due to SCC is not considered to be an aging effect requiring management for the Point Beach pressurizer bolting.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(5) **3.2.5-1 -** The staff considers the discussion in Section 3.5.2 to be extremely confusing in that it appears WOG is making three different conclusions that conflict with one another: a. That fluid flow velocity and particulate conditions are not sufficient in the pressurizer to consider that erosion is a plausible degradation mechanism that could affect the integrity of the subcomponents in the pressurizer. b. That seven components in the pressurizer (refer to the list above) are exposed to fluid flows that have the potential to result in erosion of the components. c. That only one component in the pressurizer (the spray head) is exposed to a fluid flow that has the potential to result in erosion of the component. The applicant should state why erosion is not plausible for the surge nozzle thermal sleeve, spray nozzle thermal sleeve, surge nozzle safe-end, and spray nozzle safe-end. If erosion is plausible, then an AMP is required.	Based on the aging management review of the Point Beach pressurizers, loss of material due to erosion is not an aging effect requiring management. Austenitic stainless steels are considered to be resistant to erosion in PWR operating environments. The austenitic stainless steel surge and spray nozzle thermal sleeves and safe ends, and the surge nozzle retaining baskets are not subject to flow rates that can cause erosion. The spray head couplings and the spray heads do not perform license renewal intended functions and, thus, do not require an aging management review.
(6) **3.3–1 -** Applicants for license renewal must describe how each plant-specific AMP addresses the following 10 elements: (1) scope of the program, (2) preventive action, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	Programs necessary to manage the effects of aging for the Point Beach pressurizers address the 10 elements identified. Summary descriptions of the programs are provided in this AMR. Detailed program descriptions (including the 10 elements) are provided in Appendix B of the License Renewal Application.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(7) **3.3.2.1–1 -** Applicants for license renewal must provide sufficient details in their LRAs about how their GL 88–05 programs and ISI programs will be sufficient to manage the corrosive effects of boric acid leakage on their pressurizer components during the proposed extended operating terms for their facilities, including postulated leakage from the pressurizer nozzles, pressurizer nozzle-to-vessel welds, pressurizer nozzle-to-safe end welds, and pressurizer manway bolting materials.	Loss of material and loss of mechanical closure integrity due to borated water leaks onto pressurizer carbon steel external surfaces and manway bolting are aging effects requiring management for the Point Beach pressurizers. The Boric Acid Corrosion Program is credited for managing these aging effects. The descriptions provided in Appendix B of the License Renewal Application demonstrate that this program is sufficient to manage these aging effects for the extended period of operation.
(8) **3.3.2.2–1 -** The staff concludes that an AMP is necessary to control and manage the potential for SCC to occur in welded pressurizer penetration nozzles and manway bolting materials, and recommends that a licensee could credit the following programs as the basis for managing the phenomena of PWSCC/IGSCC of the pressurizer components: (1) the primary coolant chemistry control program; (2) the ISI program for the pressurizers; and (3) the plant-specific quality assurance program as it pertains to assuring that previous welding activities on welds in the pressurizer have been controlled in accordance with the pertinent requirements of 10 CFR Part 50, Appendix B, and with the pertinent welding requirements of the ASME Code for Class 1 systems. The staff concludes that applicants need to extend AMP–2–1 to the pressurizer penetration nozzles, to the nozzle-to-vessel welds, and to the manway bolting materials, and to include the appropriate Code requirements among the program attributes listed in Table 4–1 and summarized in the text in Section 4.1 of the report. Applicants for license renewal must provide sufficient details in their LRAs as to how their primary coolant chemistry control programs, ISI programs, and 10 CFR Part 50, Appendix B, quality assurance programs will be sufficient to manage the potential for SCC to occur in the pressurizer nozzle components and bolted manway covers during the proposed extended operating terms for their facilities.	Stress corrosion cracking, as it applies to the Point Beach pressurizers, is identified as an aging effect requiring management for pressurizer nozzle parts and the bolted manway covers. Programs credited to manage cracking of pressurizer parts include the Water Chemistry Control Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The Quality Assurance Program applies to all programs credited for license renewal. The descriptions provided in Appendix B of the License Renewal Application demonstrate that these programs are sufficient to manage cracking due to SCC for the extended period of operation. As stated previously in the response to Applicant Action Item 3.2.2.3.2-1, cracking due to SCC is not an aging effect requiring management for pressurizer bolting.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(9) **3.3.2.2–2 -** Applicants must propose an AMP to verify whether or not thermal fatigue-induced cracking has propagated through the clad into the ferritic base metal or weld metal beneath the clad.	There is no industry experience to suggest that cracks initiating at the clad inner surfaces in the pressurizer will propagate into the underlying base metal or weld material. Observed flaws in other plants were monitored for an extended period of time, and no significant flaw growth was observed. In 1990, several indications were discovered at the Connecticut Yankee Plant. UT inspection confirmed that the indications did not penetrate into the ferritic base metal, and therefore, in accordance with ASME Section XI, the indications were acceptable without repair. A surveillance program was initiated, and after two follow-up inspections that showed no change, the surveillance program was discontinued with NRC approval. In several of the cases of observed cracking, fracture mechanics analyses were performed and demonstrated that the cladding indications would not compromise the integrity of the primary system components. At temperatures >180°F, the cladding has virtually no impact on fracture behavior. This is the low end of the plant operating range. ASME Section XI flaw evaluation rules require that the effects of cladding must be considered in any structural integrity evaluation, especially for postulated flaws that penetrate the cladding into the base metal. The actual impact of the cladding on such an evaluation is negligible. The pressurizer shell design considers fatigue usage throughout the operating lifetime and includes adequate margin. This is expected to preclude the formation of fatigue cracks in the cladding material. The fracture mechanics evaluations performed for actual observed cracks in other plants indicate that the cracks do not grow significantly over the plant lifetime. Therefore, a specific aging management program to manage fatigue cracking of the pressurizer cladding is not required.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(9) **3.3.2.2–2 -** Applicants must propose an AMP to verify whether or not thermal fatigue-induced cracking has propagated through the clad into the ferritic base metal or weld metal beneath the clad. (Continued)	Cracking due to fatigue is identified as a TLAA for the Point Beach pressurizers. The associated analysis concluded that cracking due to fatigue is not an aging effect requiring management.(See discussion in Table 3.1.0-3 Line Number (1)). Cracking due to flaw growth and stress corrosion, however, is an aging effect requiring management. Programs credited to manage cracking of pressurizer parts include the Water Chemistry Control Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, both of which are described in Appendix B. Based on the aging management review performed on the Point Beach pressurizers, no additional aging management program is required.

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(10) **3.3.2.2–3 -** The staff is concerned that IGSCC in the heat- affected zones of 304 stainless steel supports that are welded to the pressurizer cladding could grow as a result of thermal fatigue into the adjacent pressure boundary during the license renewal term. The staff considers that these welds will not require aging management in the extended operating periods if applicants can provide a reasonable justification that sensitization has not occurred in these welds during the fabrication of these components. Therefore, applicants for license renewal must provide a discussion of how the implementation of their plant-specific procedures and quality assurance requirements, if any, for the welding and testing of these austenitic stainless steel components provides reasonable assurance that sensitization has not occurred in these welds and their associated heat-affected zones. In addition, the staff requests that applicants for license renewal identify whether these welds fall into Item B8.20 of Section XI Examination Category B–H, Integral Attachments for Vessels, and if applicable, whether the applicants have performed the mandatory volumetric or surface examinations of these welds during the ISI intervals referenced in the examination category.	The cladding material (309L) used to protect the pressurizer alloy steel shell and the weld material (308L) used to join the pressurizer internal supports and the pressurizer cladding were selected to have sufficiently low carbon content to minimize the likelihood of sensitization of these welds. Additionally, welding processes were performed to minimize the likelihood of sensitization of stainless steels. However, the possibility cannot be precluded that sensitized areas may exist in 304 stainless steel supports or their welds.The Water Chemistry Control Program which precludes SCC in other PWR primary system materials is also effective in preventing SCC in these pressurizer components and welds. Rigorous control of oxygen and chlorides provides an essentially benign environment which has been shown to be effective both in laboratory experiments and years of operating experience. Therefore, the presence of sensitized stainless steel material does not necessarily result in any increase in susceptibility to IGSCC. Note that even in laboratory cases where severely sensitized stainless steels have been deliberately exposed to PWR environments, no intergranular attack has been observed. In summary, the Water Chemistry Control Program is an adequate aging management program to preclude SCC in the pressurizer internal attachment welds for the period of extended operation for the following reasons: 1. It is possible that some locations of the welded stainless steel attachments in the pressurizer are sensitized, even with the use of 308L weld material and careful control of the welding processes;

Table 3.1.0-3 Pressurizers - WCAP-14574-A Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(10) (continued)	2. Studies and operating experience have shown that PWR environments do not lead to stress corrosion cracking in sensitized stainless steel; 3. Service experience has demonstrated that stress corrosion cracking does not occur in stainless steels in a PWR environment, whether or not they are sensitized. In response to the question regarding the applicability of Item B8.20 of Examination Category B-H, this category applies to exterior attachments such as the support skirt, seismic lug and support bracket, and is not applicable to the interior attachment welds.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-01	Reactor coolant pressure boundary components	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA (see [SRP] subsection 3.1.2.2.1)	Further evaluation documented in Section 3.1.2.2.1.
3.1.1-02	Steam generator shell assembly	Loss of material due to pitting and crevice corrosion	Inservice inspection; water chemistry	Yes, detection of aging effects is to be further evaluated (see [SRP] subsection 3.1.2.2.2.1)	Further evaluation documented in Section 3.1.2.2.2.1.
3.1.1-03	BWR only				
3.1.1-04	Pressure vessel ferritic materials that have a neutron fluence greater than 10^{17} n/cm^2 (E>1 MeV)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G of 10 CFR 50 and RG 1.99	Yes, TLAA (see [SRP] subsection 3.1.2.2.3.1)	Further evaluation documented in Section 3.1.2.2.3.1.
3.1.1-05	Reactor vessel beltline shell and welds	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor vessel surveillance	Yes, plant specific (see [SRP] subsection 3.1.2.2.3.2)	Further evaluation documented in Section 3.1.2.2.3.2.
3.1.1-06	Westinghouse and B&W baffle/former bolts	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.3.3)	Further evaluation documented in Section 3.1.2.2.3.3.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-07	Small-bore reactor coolant system and connected systems piping	Crack initiation and growth due to SCC, intergranular SCC, and thermal and mechanical loading	Inservice inspection; water chemistry; one-time inspection	Yes, parameters monitored/ inspected and detection of aging effects are to be further evaluated (see [SRP] subsection 3.1.2.2.4.1)	Further evaluation documented in Section 3.1.2.2.4.1.
3.1.1-08	BWR only				
3.1.1-09	BWR only				
3.1.1-10	Vessel shell	Crack growth due to cyclic loading	TLAA	Yes, TLAA (see [SRP] subsection 3.1.2.2.5)	Further evaluation documented in Section 3.1.2.2.5.
3.1.1-11	Reactor internals	Changes in dimension due to void swelling	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.6)	Further evaluation documented in Section 3.1.2.2.6.
3.1.1-12	PWR core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads, and nozzles for the steam generator instruments and drains	Crack initiation and growth due to SCC and/or primary water stress corrosion cracking (PWSCC)	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.7.1)	Further evaluation documented in Section 3.1.2.2.7.1.
3.1.1-13	Cast austenitic stainless steel (CASS) reactor coolant system piping	Crack initiation and growth due to SCC	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.7.2)	Further evaluation documented in Section 3.1.2.2.7.2.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-14	Pressurizer instrumentation penetrations and heater sheaths and sleeves made of Ni-alloys	Crack initiation and growth due to PWSCC	Inservice inspection; water chemistry	Yes, AMP for PWSCC of Inconel 182 weld is to be evaluated (see [SRP] subsection 3.1.2.2.7.3)	Further evaluation documented in Section 3.1.2.2.7.3.
3.1.1-15	Westinghouse and B&W baffle former bolts	Crack initiation and growth due to SCC and IASCC	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.8)	Further evaluation documented in Section 3.1.2.2.8.
3.1.1-16	Westinghouse and B&W baffle former bolts	Loss of preload due to stress relaxation	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.9)	Further evaluation documented in Section 3.1.2.2.9.
3.1.1-17	Steam generator feedwater impingement plate and support	Loss of section thickness due to erosion	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.10)	Further evaluation documented in Section 3.1.2.2.10.
3.1.1-18	(Alloy 600) Steam generator tubes, repair sleeves, and plugs	Crack initiation and growth due to PWSCC, outside diameter stress corrosion cracking (ODSCC), and/or intergranular attack (IGA) or loss of material due to wastage and pitting corrosion, and fretting and wear: or deformation due to corrosion at tube support plate intersections	Steam generator tubing integrity; water chemistry	Yes, effectiveness of a proposed AMP is to be evaluated (see [SRP] subsection 3.1.2.2.11)	Further evaluation documented in Section 3.1.2.2.11.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-19	Tube support lattice bars made of carbon steel	Loss of section thickness due to FAC	Plant specific	Yes, plant specific (see [SRP] subsection 3.1.2.2.12)	Further evaluation documented in Section 3.1.2.2.12
3.1.1-20	Carbon steel tube support plate	Ligament cracking due to corrosion	Plant specific	Yes, effectiveness of a proposed AMP is to be evaluated (see [SRP] subsection 3.1.2.2.13)	Further evaluation documented in Section 3.1.2.2.13.
3.1.1-21	PWR (CE) only				
3.1.1-22	Reactor vessel closure studs and stud assembly	Crack initiation and growth due to SCC and/or IGSCC	Reactor head closure studs	No	Crack initiation and growth due to SCC or IGSCC are not credible without leakage past the double o-ring seals at the vessel flange. However, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides for visual, surface, and volumetric inspections capable of detecting cracking due to SCC, and is also credited for managing other aging effects applicable to the reactor head closure studs (see line item 3.1.1-47).

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-23	CASS pump casing and valve body	Loss of fracture toughness due to thermal aging embrittlement	Inservice inspection	No	Loss of fracture toughness due to thermal aging embrittlement was identified as an aging effect requiring management for the CASS reactor coolant pump (RCP) casings and Class 1 valve bodies at PBNP. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is credited for managing this aging effect for the RCP casings. Based on the methodology of code case N-481, a flaw tolerance fracture mechanics evaluation was performed for the RCP casings to verify that adequate margin exists for flaw stability after consideration is given to reduction in fracture toughness due to thermal aging embrittlement. This has been re-evaluated, and has demonstrated adequate margin throughout the period of extended operation. For Class 1 valve bodies, the ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program is credited for managing loss of fracture toughness due to thermal aging embrittlement.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-24	CASS piping	Loss of fracture toughness due to thermal aging embrittlement	Thermal aging embrittlement of CASS	No	PBNP does not have CASS RCS piping, but does have CASS primary loop elbows. Since the primary loop elbows are cast austenitic stainless steel, the Leak-Before-Break (LBB) analysis for Class 1 piping must consider the effects of thermal embrittlement. The LBB analysis has been identified as a TLAA and is discussed further in Section 4.4. The TLAA was resolved by performing a fracture mechanics evaluation considering loading, pipe geometry, and fracture toughness reduction due to thermal embrittlement to assess LBB crack stability for the period of extended operation. This evaluation demonstrates that a significant margin exists between detectable flaw size and flaw instability. PBNP has chosen the evaluation method to disposition reduction in fracture toughness due to thermal embrittlement of primary loop elbows. Accordingly, an aging management program to manage this effect for the primary loop pipe fittings is not required.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-25	BWR piping and fittings; steam generator components	Wall thinning due to flow-accelerated corrosion	Flow-accelerated corrosion	No	The aging management review for the PBNP replacement steam generators did not identify loss of material due to FAC as an aging effect requiring management for the steam outlet nozzle. The steam quality at the steam outlet nozzles is such that FAC wear-rates are not a concern. The feedwater inlet nozzles are susceptible to this aging effect. The design of the feedwater inlet nozzles include a thermal sleeve which is resistant to this aging effect. The Flow-Accelerated Corrosion Program is credited for managing this aging effect. This will be augmented by the Steam Generator Integrity Program.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-26	Reactor coolant pressure boundary (RCPB) valve closure bolting, manway and holding bolting, and closure bolting in high pressure and high temperature systems	Loss of material due to wear; loss of preload due to stress relaxation; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity	No	The closure bolting for reactor coolant system valves, reactor coolant pumps, steam generators, and pressurizers is not high-strength material. Consequently, crack initiation and growth due to SCC is not an applicable aging effect. For all reactor coolant pressure boundary (RCPB) bolting other than the reactor vessel closure studs, loss of mechanical closure integrity due to stress relaxation is managed at PBNP by the Bolting Integrity Program. The Bolting Integrity Program invokes the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program for assurance that effects of aging for RCPB closure bolting are effectively managed. Loss of mechanical closure integrity due to boric acid corrosion is also identified as an aging effect requiring management for all RCPB bolting potentially exposed to borated water leaks. This is addressed in line item 3.1.1-38, and the applicable aging management program is the Boric Acid Corrosion Program.
3.1.1-27	BWR only				
3.1.1-28	BWR only				
3.1.1-29	BWR only				
3.1.1-30	BWR only				
3.1.1-31	BWR only				
3.1.1-32	BWR only				

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-33	BWR only				
3.1.1-34	BWR only				
3.1.1-35	CRD nozzle	Crack initiation and growth due to PWSCC	Ni-alloy nozzles and penetrations; water chemistry	No	Crack initiation and growth due to PWSCC was identified as an aging effect requiring management for the Alloy 600 CRDM nozzles and reactor head vent pipe. The aging management programs credited for managing this effect are the Water Chemistry Control Program and the Reactor Coolant System Alloy 600 Inspection Program.
3.1.1-36	Reactor vessel nozzles safe ends and CRD housing; reactor coolant system components (except CASS and bolting)	Crack initiation and growth due to cyclic loading, and/or SCC, and PWSCC	Inservice inspection; water chemistry	No	Crack initiation and growth due to SCC and flaw growth are identified as aging effects requiring management for the reactor vessel nozzle safe ends, CRD housing, and RCS components. Aging management programs credited for managing these effects are the Water Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The ISI Program inspects critical component locations as determined by the ASME Code approved by the NRC. Thus, it may be noted that some components (manway inserts, thermal sleeves, SG divider plate) are not inspected by the ISI Program, and therefore ISI is not credited for these select components. Plant specific operating experience has not identified these aging effects to-date, and therefore the Water Chemistry Control Program alone has proven to be effective in managing these aging effects.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-37	Reactor vessel internals CASS components	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement, and void swelling	Thermal aging and neutron irradiation embrittlement	No	PBNP does have CASS components in the Reactor Vessel Internals that are subject to this aging effect. PBNP does not have a Thermal Aging and Neutron Irradiation Embrittlement Program. Instead, the Reactor Vessel Internals Program is used to manage this aging effect
3.1.1-38	External surfaces of carbon steel components in reactor coolant system pressure boundary	Loss of material due to boric acid corrosion	Boric acid corrosion	No	Consistent with NUREG-1801. Loss of material due to boric acid corrosion was identified as an aging effect requiring management for external surfaces of carbon steel components (including closure bolting) in the reactor coolant system pressure boundary. The Boric Acid Corrosion Program is credited for managing this aging effect.
3.1.1-39	Steam generator secondary manways and handholds (CS)	Loss of material due to erosion	Inservice inspection	No	This line item applies to once-through steam generators and is therefore not applicable to PBNP
3.1.1-40	Reactor internals, reactor vessel closure studs, and core support pads	Loss of material due to wear	Inservice inspection	No	Loss of material due to wear was identified as an aging effect requiring management for the reactor vessel flange and internals components. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program or the Reactor Vessel Internals Program is credited for managing loss of material due to wear for all components except the flux thimble tubes. For the flux thimble tubes, PBNP credits the Thimble Tube Inspection Program for managing loss of material due to wear.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-41	Pressurizer integral support	Crack initiation and growth due to cyclic loading	Inservice inspection	No	The PBNP pressurizer has no integral support other than the support skirt and flange. Cracking occurs as a result of cyclic loading (fatigue). Fatigue is a TLAA, and is addressed in Section 4.3.5 for pressurizer components.
3.1.1-42	Upper and lower internals assembly (Westinghouse)	Loss of preload due to stress relaxation	Inservice inspection; loose part and/or neutron noise monitoring	No	Loss of mechanical closure integrity due to stress-relaxation was identified as an aging effect requiring management for the holddown spring in the upper internals assembly and for the clevis-insert bolts in the lower internals assembly. The Reactor Vessel Internals Program is credited for managing this aging effect. PBNP does have on-line loose-parts monitoring and has periodically performed neutron noise measurements, but we do not credit these activities for aging management as referenced in NUREG-1801.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-43	Reactor vessel internals in fuel zone region (except Westinghouse and Babcock & Wilcox [B&W] baffle bolts)	Loss of fracture toughness due to neutron irradiation embrittlement, and void swelling	PWR vessel internals; water chemistry	No	Loss of fracture toughness due to neutron irradiation embrittlement was identified as an aging effect requiring management for reactor vessel internals components in the fuel zone. The results of recent destructive examinations of PBNP baffle/former bolts removed during the 1999 refueling outage suggest that void swelling should not represent a concern during the period of extended operation (see discussion in Item 3.1.1-11). In addition, the lower support forging and the core barrel outlet nozzle were not included among the components subject to significant irradiation embrittlement because of their location remote from the fuel zone. The aging management program referred to in NUREG-1801 is the PWR Vessel Internals Program. However, the SRP references Water Chemistry as well as the PWR Vessel Internals Program. Nevertheless, the Reactor Vessel Internals Program is credited with managing loss of fracture toughness due to neutron irradiation embrittlement and void swelling for the internals components in this component grouping. PBNP will incorporate applicable results of industry initiatives related to void swelling in the Reactor Vessel Internals Program as they become available.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-44	Steam generator upper and lower heads; tubesheets; primary nozzles and safe ends	Crack initiation and growth due to SCC, PWSCC and IASCC	Inservice inspection; water chemistry	No	Crack initiation and growth due to SCC was identified as an aging effect requiring management for the stainless steel/clad primary components. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Water Chemistry Control Program are credited for managing applicable aging effects for components in this grouping. The ISI Program inspects critical component locations as determined by the ASME Code approved by the NRC. Thus, it may be noted that some components (manway inserts) are not inspected by the ISI Program, and therefore ISI is not credited for these select components. Plant specific operating experience has not identified these aging effects to-date, and therefore the Water Chemistry Program alone has proven to be effective in managing these aging effects.

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-45	Vessel internals (except Westinghouse and B&W baffle former bolts)	Crack initiation and growth due to SCC and IASCC	PWR vessel internals; water chemistry	No	Crack initiation and growth due to SCC was identified as an aging effect requiring management for all reactor vessel internals components fabricated from stainless steel. Crack initiation and growth due to IASCC was identified as an aging effect requiring management for those components exposed to neutron fluence >1021 n/cm2 in the core. Plant-specific data obtained from destructive evaluation of Type 347 stainless steel baffle/former bolts removed in 1999 indicated very limited evidence of IASCC. PBNP credits the Water Chemistry Control Program and the Reactor Vessel Internals Program for management of crack initiation and growth due to SCC/IASCC.
3.1.1-46	Reactor internals (B&W screws and bolts)	Loss of preload due to stress relaxation	Inservice inspection; loose part monitoring	No	The components in this grouping are not applicable to PBNP.
3.1.1-47	Reactor vessel closure studs and stud assembly	Loss of material due to wear	Reactor head closure studs	No	Loss of material due to wear was identified as an aging effect requiring management for the reactor vessel closure studs. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is credited with managing this effect (see also 3.1.1-22).

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-48	Reactor internals (Westinghouse upper and lower internal assemblies; CE bolts and tie rods)	Loss of preload due to stress relaxation	Inservice inspection; loose part monitoring	No	Loss of mechanical closure integrity due to stress relaxation was identified as an aging effect requiring management for the upper and lower support plate column bolts. NUREG-1801 cites the Loose Parts Monitoring Program as well as the ASME Section XI ISI Program for managing this aging effect. Loose-parts monitoring is not considered to be effective as an aging management program at PBNP. The Reactor Vessel Internals Program is credited for managing this aging effect at PBNP, in lieu of the ASME Section XI ISI Program.

Table 3.1.2-1 Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Bolting for Flanged Piping Joints, RCP and Valve Closure	Mechanical Closure Integrity	Low Alloy Steel	Borated Water Leaks (External)	Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.C2.3-f, IV.C2.4-f	3.1.1-38	A
			Containment (External)	Loss of Mechanical Closure Integrity due to Stress Relaxation	Bolting Integrity Program	IV.C2.3-g, IV.C2.4-g	3.1.1-26	B, 7
Orifices and Reducers	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, 140°F<T<480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	(IV.C2.2-h)	(3.1.1-07)	D, 20
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.2-h)	(3.1.1-07)	H, 5, 21
	Restrict Flow (Throttling)	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, 140°F<T<480°F (Internal)	Erosion	One-Time Inspection Program	(IV.C2.2-h)	(3.1.1-07)	H, 5, 39

Table 3.1.2-1 Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings < 4 in. NPS	Pressure Boundary	Wrought Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.1-g, IV.C2.2-h	3.1.1-07	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.1-g, IV.C2.2-h	3.1.1-07	B
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.1-g, IV.C2.2-h)	(3.1.1-07)	H, 5, 21
Piping and Fittings ≥ 4 in. NPS	Pressure Boundary	Wrought Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.1-c, IV.C2.2-f	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.1-c, IV.C2.2-f	3.1.1-36	B
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.1-c, IV.C2.2-f)	(3.1.1-36)	H, 5, 21

Table 3.1.2-1 Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping Welds and Vent Connections (Nickel Alloys)	Pressure Boundary	Alloy 690 and 82/152 Weld Material (Unit 2 only)	Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.C2.1-c)	(3.1.1-36)	F, 5
					Reactor Coolant System Alloy 600 Inspection Program	(IV.A2.7-b)	(3.1.1-35)	D
					Water Chemistry Control Program	(IV.C2.1-c)	(3.1.1-36)	F, 5
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.1-c)	(3.1.1-36)	F, 5, 21
Primary Loop Elbows	Pressure Boundary	Cast Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.1-e	3.1.1-13	4
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.1-e	3.1.1-13	B
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.1-e)	(3.1.1-13)	H, 5, 21
Reactor Coolant Pump Lugs	Structural Support	Stainless Steel	Containment (External)	Cracking due to Flaw Growth	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program			J, 5

Table 3.1.2-1 Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Reactor Coolant Pumps (casing and main flange)	Pressure Boundary	Cast Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.3-b	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.3-b	3.1.1-36	B
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.3-b)	(3.1.1-36)	H, 5, 21
				Reduction in Fracture Toughness due to Thermal Embrittlement	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.3-c	3.1.1-23	B
Reactor Coolant Pumps (thermal barrier flange)	Pressure Boundary	Wrought Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.C2.3-b)	(3.1.1-36)	F, 5
				Cracking due to SCC	Water Chemistry Control Program	(IV.C2.3-b)	(3.1.1-36)	F, 5
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.3-b)	(3.1.1-36)	H, 5, 21

Table 3.1.2-1 Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Thermal Barrier Heat Exchanger Tubing	Pressure Boundary	Stainless Steel	Treated Water - Other	Cracking due to SCC	Closed-Cycle Cooling Water System Surveillance Program			J, 5
				Loss of Material due to Corrosion	Closed-Cycle Cooling Water System Surveillance Program			J, 5
Thermowells	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	(IV.C2.1-g, IV.C2.2-h)	(3.1.1-07)	B, 20
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.1-g, IV.C2.2-h)	(3.1.1-07)	H, 5, 21
Valves < 4in. NPS	Pressure Boundary	Cast Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.4-b	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.4-b	3.1.1-36	B
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	H, 5, 21
				Reduction in Fracture Toughness due to Thermal Embrittlement	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.4-c	3.1.1-23	B

Table 3.1.2-1 Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valves < 4in. NPS	Pressure Boundary	Wrought Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
				Cracking due to SCC	Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5, 21
Valves ≥ 4 in. NPS	Pressure Boundary	Carbon Steel (strongback only)	Containment (External)	None	None Required			J
			Borated Water Leaks (External)	Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack	Boric Acid Corrosion Program	(IV.C2.4-f)	(3.1.1-38)	C
		Cast Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.4-b	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.4-b	3.1.1-36	B
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	H, 5, 21

Table 3.1.2-1 Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valves ≥ 4 in. NPS	Pressure Boundary	Cast Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Reduction in Fracture Toughness due to Thermal Embrittlement	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.4-c	3.1.1-23	B
		Wrought Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
				Cracking due to SCC	Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
				Loss of Material due to Corrosion	Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5, 21

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
BMI Guide Tubes	Pressure Boundary	Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program			J, 5
	Support Thimble Tubes	Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program			J, 5
Bottom Head Dome	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	None	None Required			J

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Bottom Head Dome	Pressure Boundary	Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
	Support RV Internals	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
Bottom Head Torus	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Bottom Head Torus	Support RV Internals	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
Closure Head Dome	Pressure Boundary	Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
Closure Head Dome (Including Lifting Lugs)	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.1-a	3.1.1-38	A
			Containment (External)	None	None Required			J

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Closure Head Flange	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.1-a	3.1.1-38	A
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
Closure Studs, Nuts, and Washers	Mechanical Closure Integrity	Low Alloy Steel	Borated Water Leaks (External)	Cracking due to SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.1-c	3.1.1-22	E, 6
				Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.A2.1-a	3.1.1-38	A
			Containment (External)	Loss of Material due to Wear	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.1-d	3.1.1-47	E, 6
				Loss of Mechanical Closure Integrity due to Stress Relaxation	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.1-d)	(3.1.1-47)	H, 5

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Core Support Pads	Support RV Internals	Alloy 600	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.6-a	3.1.1-12	4
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.6-a	3.1.1-12	4
				Loss of Material due to Wear	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.6-a)	(3.1.1-12) (3.1.1-40)	H, 5
CRDM Housing Tubes (Head Adapters)	Pressure Boundary	Alloy 600	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	Reactor Coolant System Alloy 600 Inspection Program	IV.A2.2-a	3.1.1-35	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.2-a	3.1.1-35	B

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CRDM Housings and Flanges (Rod Travel and Latch)	Pressure Boundary	Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.2-b	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.2-b	3.1.1-36	B
Instrumentation Tubes and Safe Ends	Pressure Boundary	Alloy 600 Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	Reactor Coolant System Alloy 600 Inspection Program	IV.A2.7-a	3.1.1-12	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.7-a	3.1.1-12	B
	Support Thimble Tubes	Alloy 600 Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrumentation Tubes and Safe Ends	Support Thimble Tubes	Alloy 600 Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	Reactor Coolant System Alloy 600 Inspection Program	IV.A2.7-a	3.1.1-12	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.7-a	3.1.1-12	B
Intermediate Shell (including circumferential Beltline weld)	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
				Reduction in Fracture Toughness due to Irradiation Embrittlement	Reactor Vessel Surveillance Program	IV.A2.5-c	3.1.1-05	B
Lower Shell	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	None	None Required			J

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Lower Shell	Pressure Boundary	Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
				Reduction in Fracture Toughness due to Irradiation Embrittlement	Reactor Vessel Surveillance Program	IV.A2.5-c	3.1.1-05	B
Nozzle Support Pads and External Support Brackets	Structural Support	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	(IV.A2.5.e)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
Primary Inlet Nozzles	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	(IV.A2.5.e)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.4-b	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.4-b	3.1.1-36	B

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Primary Nozzle Safe Ends	Pressure Boundary	Stainless Steel Weld Butter	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.4-b	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.4-b	3.1.1-36	B
Primary Outlet Nozzles	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	(IV.A2.5.e)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.4-b	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.4-b	3.1.1-36	B
Refueling Seal Ledge	Structural Support	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	(IV.A2.5.e)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
RV Components (in contact with primary water)	Pressure Boundary	Alloy 600 Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Loss of Material due to Corrosion	Water Chemistry Control Program			J, 5, 21

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Seal Table Fittings	Pressure Boundary	Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T<140°F (Internal)	Cracking due to SCC	Water Chemistry Control Program			J, 5
	Support Thimble Tubes	Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T<140°F (Internal)	Cracking due to SCC	Water Chemistry Control Program			J, 5
Upper Shell	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	None	None Required			J
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Vent Pipe	Pressure Boundary	Alloy 600 Stainless Steel	Borated Water Leaks (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	Reactor Coolant System Alloy 600 Inspection Program	IV.A2.7-b	3.1.1-35	B
				Cracking due to SCC	Water Chemistry Control Program	IV.A2.7-b	3.1.1-35	B
Ventilation Shroud Support Ring	Structural Support	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.1-a	3.1.1-38	A
			Containment (External)	None	None Required			J

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Vessel Flange	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	Loss of Material due to Wear	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.5-f	3.1.1-40	B
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D
	Support RV Internals	Low Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Boric Acid Corrosion	Boric Acid Corrosion Program	IV.A2.5.e	3.1.1-38	A
			Containment (External)	Loss of Material due to Wear	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.A2.5-f	3.1.1-40	B
		Low Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.A2.4-b)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.A2.4-b)	(3.1.1-36)	D

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Baffle and Former Plates	Flow Distribution Gamma/ Neutron Shielding Support Core	ASTM A240 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.4-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.4-a	3.1.1-45	B
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	IV.B2.4-e	3.1.1-43	B
RVI Baffle/Barrel -Former Bolts	Flow Distribution Secondary Core Support Support Core Support In-core Instrumenta-tion Support RCCAs	Type 347, 316 or 304 SS	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.4-c	3.1.1-15	4
					Water Chemistry Control Program	IV.B2.4-c	3.1.1-15	4
				Loss of Preload	Reactor Vessel Internals Program	IV.B2.4-h	3.1.1-16	4
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	IV.B2.4-f	3.1.1-06	4
RVI Bottom Mounted Instrumentation Column cruciforms	Support In-core Instrumenta-tion	ASTM A296, CF-8 - ASTM A743/A744 (castings)	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.5-k)	(3.1.1-45)	D
					Water Chemistry Control Program	(IV.B2.5-k)	(3.1.1-45)	D
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	(IV.B2.5-m)	(3.1.1-37)	E, 6

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Bottom Mounted Instrumentation Columns	Support In-core Instrumentation	SS Type 304 flats, ASTM A276 /A269 /A213 /A298 (weld) Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.6-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.6-a	3.1.1-45	B
RVI Clevis Insert Bolt Locking Mechanisms	Flow Distribution Secondary Core Support Support Core Support In-core Instrumentation Support RCCAs	ASTM B166 (Inconel 600)	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.5-e)	(3.1.1-45)	D
					Water Chemistry Control Program	(IV.B2.5-e)	(3.1.1-45)	D
RVI Clevis Insert Bolts	Flow Distribution Secondary Core Support Support Core Support In-core Instrumentation Support RCCAs	W PDS-70041-EJ (Inconel X-750)	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.5-e	3.1.1-45	B, 22
					Water Chemistry Control Program	IV.B2.5-e	3.1.1-45	B, 22
				Loss of Preload	Reactor Vessel Internals Program	IV.B2.5-i	3.1.1-42	E, 6, 22

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Clevis Inserts	Support Core	ASTM B166 (Inconel 600) #6 Hayes Stellite coating	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.5-a)	(3.1.1-45)	F, 5
					Water Chemistry Control Program	(IV.B2.5-a)	(3.1.1-45)	F, 5
				Loss of Material Due to Wear	Reactor Vessel Internals Program	(IV.B2.5-o)	(3.1.1-40)	F, E, 6
RVI Core Barrel - plates	Flow Distribution Gamma/ Neutron Shielding Support Core	ASTM A240 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.3-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.3-a	3.1.1-45	B
				Reduction in fracture toughness	Reactor Vessel Internals Program	IV.B2.3-c	3.1.1-43	B
RVI Core Barrel Flange – ring forging, Core Barrel (guide key)	Flow Distribution Gamma/ Neutron Shielding Support Core	ASTM A182 F304, Type 304 SS bar – U2	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.3-a	3.1.1-45	B, 22
					Water Chemistry Control Program	IV.B2.3-a	3.1.1-45	B, 22
RVI Core Barrel Outlet Nozzle - Nozzle forgings	Flow Distribution	ASTM A182 F304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.3-a	3.1.1-45	B, 22
					Water Chemistry Control Program	IV.B2.3-a	3.1.1-45	B, 22
RVI Exposed surfaces and crevice locations	NOTE[a]	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Loss of Material	Water Chemistry Control Program	(IV.B2.3-a)	(3.1.1-45)	H, 21

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI RCCA Flexures, GT Support pin (split pin)	Support RCCAs	Inconel X-750, and U1 - Inconel X-750, U2-Inconel X-750 original and Rev. B	Treated Water - Primary, T>480°F (Internal)	Cracking	Water Chemistry Control Program	IV.B2.2-d	3.1.1-45	B
					Reactor Vessel Internals Program	IV.B2.2-d	3.1.1-45	B
RVI Flux Thimbles	Pressure Boundary Support In-core Instrumenta-tion	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.6-a)	(3.1.1-45)	D
					Water Chemistry Control Program	(IV.B2.6-a)	(3.1.1-45)	D
				Loss of Material Due to Wear	Thimble Tube Inspection Program	IV.B2.6-c	3.1.1-40	B
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	(IV.B2.6-c)	(3.1.1-40)	H, 5
RVI Head and Vessel Alignment Pins	Support RCCAs	Type 304 SS bar	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.1-i)	(3.1.1-45)	D
					Water Chemistry Control Program	(IV.B2.1-i)	(3.1.1-45)	D

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI High temperature and neutron fluence locations	NOTE[a]	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Dimensional Change	Reactor Vessel Internals Program	IV.B2.1-b, IV.B2.1-f, IV.B2.1-j, IV.B2.2-b, IV.B2.2-e, IV.B2.3-b, IV.B2.4-b, IV.B2.4-d, IV.B2.5-b, IV.B2.5-f, IV.B2.5-l, IV.B2.6-b	3.1.1-11	4
RVI Holddown Spring	Support Core	W PS 10725-HA Rev C, AISI 403	Treated Water - (Internal) Primary, T>480°F	Cracking	Reactor Vessel Internals Program	IV.B2.1-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-a	3.1.1-45	B
				Loss of Preload	Reactor Vessel Internals Program	IV.B2.1-d	3.1.1-42	E, 6
RVI Lower Core Plate	Flow Distribution Secondary Core Support Support Core Support In-core Instrumenta-tion	ASTM A240 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.5-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.5-a	3.1.1-45	B
				Reduction in fracture toughness	Reactor Vessel Internals Program	IV.B2.5-c	3.1.1-43	B

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Lower Core Plate Fuel Alignment Pins	Flow Distribution Secondary Core Support Support Core Support In-core Instrumentation	ASTM A276 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.5-e	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.5-e	3.1.1-45	B
				Reduction in fracture toughness	Reactor Vessel Internals Program	IV.B2.5-g	3.1.1-43	B
RVI Lower Support Columns, Sleeves	Support In-core Instrumentation Secondary Core Support Support Core	ASTM A276 Type 304 ASTM A312 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.5-k	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.5-k	3.1.1-45	B
				Reduction in fracture toughness	Reactor Vessel Internals Program	IV.B2.5-n	3.1.1-43	B
RVI Lower Support Forging	Flow Distribution Secondary Core Support Support Core Support In-core Instrumentation	ASTM A182 F304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.5-k	3.1.1-45	B, 22
					Water Chemistry Control Program	IV.B2.5-k	3.1.1-45	B, 22

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Lower Support Plate Column Bolts/Nuts	Flow Distribution Secondary Core Support Support Core Support In-core Instrumenta-tion Support RCCAs	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.5-e	3.1.1-45	B, 22
					Water Chemistry Control Program	IV.B2.5-e	3.1.1-45	B, 22
				Loss of Preload	Reactor Vessel Internals Program	IV.B2.5-h	3.1.1-48	E, 6
RVI Radial Support Keys	Support Core	ASTM A240 Type 304, #6; Hayes Stellite coating	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.5-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.5-a	3.1.1-45	B
				Loss of Material Due to Wear	Reactor Vessel Internals Program	IV.B2.5-o	3.1.1-40	E, 6
RVI RCCA Guide Tube Bolts	Flow Distribution Secondary Core Support Support Core Support In-core Instrumenta-tion Support RCCAs	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.2-d	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.2-d	3.1.1-45	B

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI RCCA Guide Tubes, Inserts, and Flow Downcomers	Support RCCAs	ASTM A276 and A240 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.2-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.2-a	3.1.1-45	B
RVI Secondary Core Support - base plate, energy absorber, Diffuser Plate (Flow Mixer Plate)	Flow Distribution Secondary Core Support Support Core Support In-core Instrumenta-tion	ASTM A276 /A240 /276 /240 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.5-k)	(3.1.1-45)	D, 22
					Water Chemistry Control Program	(IV.B2.5-k)	(3.1.1-45)	D, 22
RVI Secondary Core Support Assy - guide post, housing	Flow Distribution Secondary Core Support Support Core Support In-core Instrumenta-tion	ACI CF-8 Type 304 – U2	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.5-k)	(3.1.1-45)	D
					Water Chemistry Control Program	(IV.B2.5-k)	(3.1.1-45)	D
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	(IV.B2.5-m)	(3.1.1-37)	E, 6
RVI (Head-Cooling) Spray nozzle bodies, and nozzle tips	Flow Distribution	Type 304 SS bar – U2, ASTM A276 Type 304 – U2	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.1-a)	(3.1.1-45)	D
					Water Chemistry Control Program	(IV.B2.1-a)	(3.1.1-45)	D

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Thermal shield - plate material, flexures, Dowel Pin	Gamma/ Neutron Shielding	ASTM A240/A240/A276 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.3-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.3-a	3.1.1-45	B
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	IV.B2.3-c	3.1.1-43	B
RVI Upper Core Plate	Flow Distribution Support Core	ASTM A240 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.1-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-a	3.1.1-45	B
				Reduction in fracture toughness	Reactor Vessel Internals Program	(IV.B2.3-c)	(3.1.1-43)	H, 5
RVI Upper Core Plate Alignment Pin	Support RCCAs	ASTM A276 / 304 SS bar – U2, Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.1-i	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-i	3.1.1-45	B
				Loss of Material Due to Wear	Reactor Vessel Internals Program	IV.B2.1-l	3.1.1-40	E, 6
RVI Upper Core Plate Fuel Alignment Pin	Flow Distribution Support Core	ASTM A276 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.1-i	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-i	3.1.1-45	B
				Reduction in fracture toughness	Reactor Vessel Internals Program	(IV.B2.3-c)	(3.1.1-43)	H, 5

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Upper Instrumentation Column, Conduit (tubing and supports), Spacers/ Clamps	Support In-core Instrumenta-tion	Stainless steel	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	(IV.B2.1-a)	(3.1.1-45)	D
					Water Chemistry Control Program	(IV.B2.1-a)	(3.1.1-45)	D
RVI Upper Support Column and Bottom Nozzles	Support In-core Instrumenta-tion Support RCCAs	ASTM A213 /A249 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.1-e	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-e	3.1.1-45	B
RVI Upper Support Column-instr. Fittings- for installation of instrumentation.	Support In-core Instrumenta-tion Support RCCAs	ASTM A276 / A240 / A351 (castings) / A213	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.1-e	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-e	3.1.1-45	B
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	IV.B2.1-g	3.1.1-37	E, 6
RVI Upper Support Column-USC Base castings	Support In-core Instrumenta-tion Support RCCAs	ASTM A351 CF-8– U2	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.1-e	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-e	3.1.1-45	B
				Reduction in Fracture Toughness	Reactor Vessel Internals Program	IV.B2.1-g	3.1.1-37	E, 6

Table 3.1.2-3 Reactor Coolant System - Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
RVI Upper Support Column Bolts	Flow Distribution Secondary Core Support Support Core Support In-core Instrumenta-tion Support RCCAs	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Loss of Preload	Reactor Vessel Internals Program	IV.B2.1-k	3.1.1-48	E, 6
				Cracking	Reactor Vessel Internals Program	IV.B2.1-i	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-i	3.1.1-45	B
RVI Upper Support Plate, deep beam weldment, top plate, ribs, hollow rounds	Support RCCAs	ASTM A240 Type 304	Treated Water - Primary, T>480°F (Internal)	Cracking	Reactor Vessel Internals Program	IV.B2.1-a	3.1.1-45	B
					Water Chemistry Control Program	IV.B2.1-a	3.1.1-45	B

a. For generic effects that apply to any component regardless of intended function.

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Heater Well and Heater Sheath	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-r	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-r	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-r)	(3.1.1-36)	H, 21
PZR Instrument Nozzles	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-g	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-g	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-g)	(3.1.1-36)	H, 21

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Lower Head	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.C2.5-b	3.1.1-38	A
			Containment (External)	None	None Required			J
		Carbon Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-c	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-c	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-c)	(3.1.1-36)	H, 21
PZR Manway Cover	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.C2.5-o	3.1.1-38	A
			Containment (External)	None	None Required			J
		Carbon Steel w/ Stainless Steel Disc Insert	Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC (disc insert)	Water Chemistry Control Program	IV.C2.5-m	3.1.1-36	B, 20
				Loss of Material (disc insert)	Water Chemistry Control Program	(IV.C2.5-m)	(3.1.1-36)	H, 21

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Manway Cover Bolts	Mechanical Closure Integrity	Low Alloy Steel	Borated Water Leaks (External)	Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.C2.5-o	3.1.1-38	A
			Containment Air (External)	Loss of Mechanical Closure Integrity due to Stress Relaxation	Bolting Integrity Program	IV.C2.5-p	3.1.1-26	B, 7
PZR Relief Nozzle	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive	Boric Acid Corrosion Program	(IV.C2.5-b)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
		Carbon Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.C2.5-g)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.C2.5-g)	(3.1.1-36)	D
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-g)	(3.1.1-36)	H, 21

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Relief Nozzle Safe End	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-h	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-h	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	H, 21
PZR Safety Nozzle	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	(IV.C2.5-b)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
		Carbon Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.C2.5-g)	(3.1.1-36)	D
				Cracking due to SCC	Water Chemistry Control Program	(IV.C2.5-g)	(3.1.1-36)	D
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-g)	(3.1.1-36)	H, 21

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Safety Nozzle Safe End	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-h	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-h	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	H, 21
PZR Shell	Pressure Boundary	Alloy Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.C2.5-b	3.1.1-38	A
			Containment (External)	None	None Required			J
		Alloy Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-c	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-c	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-c)	(3.1.1-36)	H, 21

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Spray Nozzle	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	(IV.C2.5-b)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
		Carbon Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-g	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-g	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-g)	(3.1.1-36)	H, 21
PZR Spray Nozzle Safe End	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-h	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-h	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	H, 21
PZR Spray Nozzle Thermal Sleeve	Pressure Boundary	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	D, 20
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	H, 21

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Support Skirt and Flange	Structural Support	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.C2.5-u	3.1.1-38	A
			Containment (External)	None	None Required			J
PZR Surge Nozzle	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	(IV.C2.5-b)	(3.1.1-38)	C
			Containment (External)	None	None Required			J
		Carbon Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-g	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-g	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-g)	(3.1.1-36)	H, 21

Table 3.1.2-4 Reactor Coolant System - Pressurizer - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
PZR Surge Nozzle Safe End	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-h	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-h	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	H, 21
PZR Surge Nozzle Thermal Sleeve	Pressure Boundary	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	D, 20
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-h)	(3.1.1-36)	H, 21
PZR Upper Head	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.C2.5-b	3.1.1-38	A
			Containment (External)	None	None Required			J
		Carbon Steel w/ Stainless Steel Cladding	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.C2.5-c	3.1.1-36	B
				Cracking due to SCC	Water Chemistry Control Program	IV.C2.5-c	3.1.1-36	B
				Loss of Material	Water Chemistry Control Program	(IV.C2.5-c)	(3.1.1-36)	H, 21

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG Anti-vibration Bars	Provide Support	Chrome-plated Alloy 600 (U1)/SS (U2)	Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	(IV.D1.2-h)	(3.1.1-19)	F, H, 4
					Steam Generator Integrity Program	(IV.D1.2-h)	(3.1.1-19)	F, H, 4
SG Blowdown Piping Nozzles and Secondary Side Shell Penetrations	Pressure Boundary	Alloy Steel	Containment (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Loss of Material	Steam Generator Integrity Program	(IV.D1.1-c)	(3.1.1-02)	C, 20
					Water Chemistry Control Program	(IV.D1.1-c)	(3.1.1-02)	D, 20
SG Components (in contact with primary water)	Pressure Boundary	Stainless Steel Alloy 600/690	Treated Water - Primary, T>480°F (Internal)	Loss of Material	Water Chemistry Control Program	(IV.D1.1-i)	(3.1.1-44)	H, 21
SG Divider Plate	Flow Distribution	Alloy 600/690	Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	(IV.D1.1-i)	(3.1.1-44)	D, 20

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG Feedwater Nozzle	Pressure Boundary	Alloy Steel	Containment (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to Flaw Growth	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.D1.1-c)	(3.1.1-02)	H, 5
				Loss of Material	Steam Generator Integrity Program	(IV.D1.1-c)	(3.1.1-02)	C, 23
					Water Chemistry Control Program	(IV.D1.1-c)	(3.1.1-02)	D, 23
				Loss of Material due to FAC	Flow-Accelerated Corrosion Program	IV.D1.1-d	3.1.1-25	A
					Steam Generator Integrity Program	IV.D1.1-d	3.1.1-25	34
SG Primary Channel Head	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.D1.1-g	3.1.1-38	A
			Containment (External)	None	None Required			J
		Carbon Steel w/ SS Clad	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.D1.1-i	3.1.1-44	B
				Cracking due to SCC	Water Chemistry Control Program	IV.D1.1-i	3.1.1-44	B

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG Primary Inlet and Outlet Nozzle Safe Ends	Pressure Boundary	SS Weld Butter (U1)/SS(U2)	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.D1.1-i	3.1.1-44	B
				Cracking due to SCC	Water Chemistry Control Program	IV.D1.1-i	3.1.1-44	B
			Containment (External)	None	None Required			J
SG Primary Inlet and Outlet Nozzles	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.D1.1-g	3.1.1-38	A
			Containment (External)	None	None Required			J
		Carbon Steel w/ SS Clad	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.D1.1-i	3.1.1-44	B
				Cracking due to SCC	Water Chemistry Control Program	IV.D1.1-i	3.1.1-44	B
SG Primary Manway Bolting	Pressure Boundary	Low Alloy Steel	Borated Water Leaks (External)	Loss of Mechanical Closure Integrity due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.D1.1-k	3.1.1-38	A
				Loss of Mechanical Closure Integrity due to Stress Relaxation	Bolting Integrity Program	(IV.D1.1-l)	(3.1.1-26)	B, 7

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG Primary Manways	Pressure Boundary	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	IV.D1.1-k	3.1.1-38	A
			Containment (External)	None	None Required			J
		Carbon Steel with SS Disc Insert	Treated Water - Primary, T>480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	IV.D1.1-i	3.1.1-44	B, 20
SG Secondary Closures	Pressure Boundary	Carbon Steel	Containment (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Loss of Material	Steam Generator Integrity Program	(IV.D1.1-c)	(3.1.1-02)	C, 20
					Water Chemistry Control Program	(IV.D1.1-c)	(3.1.1-02)	D, 20
SG Secondary Side Closure Bolting	Pressure Boundary	Low Alloy Steel	Containment (External)	Fatigue Cracking	Periodic Surveillance and Preventive Maintenance Program			H, 37
				Loss of Mechanical Closure Integrity due to Stress Relaxation	Bolting Integrity Program	IV.D1.1-f	3.1.1-26	B, 7
SG Seismic Lugs	Provide Support	Alloy Steel	Containment (External)	None	None Required			J
SG Steam Flow Limiter	Restrict Flow (Throttling)	Alloy 600/690	Treated Water - Secondary, T>120°F (Internal)	Loss of Material	Water Chemistry Control Program			J, 5

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG Tube Plugs (mechanical)	Pressure Boundary	Alloy 690 TT	Treated Water - Primary, T>480°F (Internal)	Cracking due to PWSCC	Steam Generator Integrity Program	IV.D1.2-i	3.1.1-18	A
					Water Chemistry Control Program	IV.D1.2-i	3.1.1-18	B
SG Steam Outlet Nozzle	Pressure Boundary	Alloy Steel	Containment (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to Flaw Growth	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.D1.1-c)	(3.1.1-02)	H, 5, 38
				Loss of Material	Steam Generator Integrity Program	(IV.D1.1-c)	(3.1.1-02)	C, 23(U1), 20(U2)
					Water Chemistry Control Program	(IV.D1.1-c)	(3.1.1-02)	D, 23(U1), 20(U2)
SG Support Pads	Provide Support	Carbon Steel	Borated Water Leaks (External)	Loss of Material due to Aggressive Chemical Attack	Boric Acid Corrosion Program	(IV.D1.1-g)	(3.1.1-38)	C
			Containment (External)	None	None Required			J

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG Transition Cone Girth Weld	Pressure Boundary	Alloy Steel	Containment (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Loss of Material	Steam Generator Integrity Program	IV.D1.1-c	3.1.1-02	A, 23(U1), 20(U2)
					Water Chemistry Control Program	IV.D1.1-c	3.1.1-02	B, 23(U1), 20(U2)
SG Transition Cone Girth Weld (U1 only)	Pressure Boundary	Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Cracking due to Flaw Growth	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.D1.1-c	3.1.1-02	H, 5, 38
SG Tube Bundle Wrapper and Wrapper Support System	Provide Support	Carbon Steel	Treated Water - Secondary, T>120°F (Internal)	Loss of Material	Steam Generator Integrity Program	(IV.D1.1-c)	(3.1.1-02)	C, 20
					Water Chemistry Control Program	(IV.D1.1-c)	(3.1.1-02)	D, 20
SG Tube Support Plates	Provide Support	Stainless Steel	Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	Steam Generator Integrity Program	(IV.D1.2-k)	(3.1.1-20)	F, 5
					Water Chemistry Control Program	(IV.D1.2-k)	(3.1.1-20)	F, 5

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG Tubesheet	Pressure Boundary	Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Cracking due to Flaw Growth	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	(IV.D1.1-c)	(3.1.1-02)	H, 5
				Loss of Material	Steam Generator Integrity Program	(IV.D1.1-c)	(3.1.1-02)	C, 23
					Water Chemistry Control Program	(IV.D1.1-c)	(3.1.1-02)	D, 23
		Alloy Steel, Alloy 600/690 clad	Treated Water - Primary, T>480°F (Internal)	Cracking due to Flaw Growth or SCC	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.D1.1-i	3.1.1-44	B
				Cracking due to SCC	Water Chemistry Control Program	IV.D1.1-i	3.1.1-44	B
SG Upper and Lower Shell, Elliptical Head and Transition Cone	Pressure Boundary	Alloy Steel	Containment (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to Flaw Growth	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program	IV.D1.1-c	3.1.1-02	H, 5
				Loss of Material	Steam Generator Integrity Program	IV.D1.1-c	3.1.1-02	A, 23
					Water Chemistry Control Program	IV.D1.1-c	3.1.1-02	B, 23

Table 3.1.2-5 Reactor Coolant System - Steam Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
SG U-Tubes	Pressure Boundary	Alloy 600/690 TT	Treated Water - Primary, T>480°F (Internal)	Cracking due to PWSCC	Steam Generator Integrity Program	IV.D1.2-a	3.1.1-18	A
					Water Chemistry Control Program	IV.D1.2-a	3.1.1-18	B
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to IGA/IGSCC	Steam Generator Integrity Program	IV.D1.2-b, IV.D1.2-c	3.1.1-18	A
					Water Chemistry Control Program	IV.D1.2-b, IV.D1.2-c	3.1.1-18	B
				Loss of Material due to Pitting	Steam Generator Integrity Program	IV.D1.2-f	3.1.1-18	A
					Water Chemistry Control Program	IV.D1.2-f	3.1.1-18	B
				Loss of Material due to Wear	Steam Generator Integrity Program	IV.D1.2-e	3.1.1-18	A

Table 3.1.2-6 Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	(VII.I.1-a)	(3.3.1-14)	35, A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	(VII.I.2-a)	(3.3.1-24)	35, B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	(VII.I.2-a)	(3.3.1-24)	35, B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Flow Indicators[a]	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	H, 3
					Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	H, 3
Flywheel	Flow Control	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.I.1-b)	(3.3.1-05)	35, 4
			N/A (Internal)	None	None Required			2

Table 3.1.2-6 Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	35, 4
			Oil and Fuel Oil (Internal)	Loss Of Material	One-Time Inspection Program	(VII.G.7-b)	(3.3.1-06)	35, C
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C2.1-a)	(3.3.1-15)	35, D
					One-Time Inspection Program	(VII.C2.1-a)	(3.3.1-15)	35, 34
		Copper Alloy (Zn < 15%)	N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss Of Material	One-Time Inspection Program	(VII.G.7-b)	(3.3.1-06)	35, C
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C2.1-a)	(3.3.1-15)	35, F, 5
					One-Time Inspection Program	(VII.C2.1-a)	(3.3.1-15)	35, F, 5
Heat Exchanger	Pressure Boundary	Copper Alloy (Zn > 15%)	N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss Of Material	One-Time Inspection Program	(VII.G.7-b)	(3.3.1-06)	35, C
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C2.1-a)	(3.3.1-15)	35, F, 5
					One-Time Inspection Program	(VII.C2.1-a)	(3.3.1-15)	35, F, 5

Table 3.1.2-6 Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	H, 3
				Loss Of Material	Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	H, 3
			Treated Water - Primary, T>480°F (Internal)	Cracking due to IGA/IGSCC	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	34, 20
					Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	B, 20
				Cracking due to SCC	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	34, 20
					Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	B, 20
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Treated Water - Primary, T>480°F (Internal)	Loss Of Material	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	H, 3
					Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	H, 3

Table 3.1.2-6 Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	35, 4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	35, 4
			Treated Water - Primary, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	H, 3
					Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	H, 3
Piping and Fittings	Pressure Boundary	Stainless Steel	Treated Water - Primary, 140°F<T<480°F (Internal)	Cracking due to SCC	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	34, 20
					Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	B, 20
				Loss Of Material	One-Time Inspection Program	IV.C2.2-f	3.1.1-36	H, 3
					Water Chemistry Control Program	IV.C2.2-f	3.1.1-36	H, 3

Table 3.1.2-6 Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Seal Table	Support In-Core Instrumenta-tion	Stainless Steel	Containment (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Tanks	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Primary, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	IV.C2.6-c	3.1.1-36	H, 3
					Water Chemistry Control Program	IV.C2.6-c	3.1.1-36	H, 3
Thermowells	Pressure Boundary	Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
			Containment (External)	None	None Required			J

Table 3.1.2-6 Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	35, 36, 4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	35, 36, 4
		Copper Alloy (Zn > 15%)	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.1.2-6 Reactor Coolant System - Non-Class 1 RCS Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	35, 4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	35, 4
			Treated Water - Primary, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(IV.C2.4-b)	(3.1.1-36)	F, 5, 21, 34
					Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5, 21
			Treated Water - Primary, T>480°F (Internal)	Cracking due to IGA/IGSCC	One-Time Inspection Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
					Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
				Cracking due to SCC	One-Time Inspection Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
					Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5
				Loss Of Material	One-Time Inspection Program	(IV.C2.4-b)	(3.1.1-36)	F, 5, 21, 34
					Water Chemistry Control Program	(IV.C2.4-b)	(3.1.1-36)	F, 5, 21
Valve Operator	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	35, 4

a. Selected instruments were conservatively included within the scope of License Renewal. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for License Renewal review.

Notes for Tables 3.1.2-1 through 3.1.2-6

A Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP has exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP has exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect but a different AMP is credited.

F Material not in NUREG-1801 for this component.

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

I Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-specific notes:

1 The CS Component asset was created to manage Boric Acid wastage of external surfaces only (for any carbon steel, low alloy steel, or cast iron component, including bolting), and therefore internal environments for this asset are not applicable. All other internal and external aging effects are identified separately under the specific component type.

2 Internal aging effects are not applicable. Due to the way data is entered into the LRDB, the internal environment of some components is listed as N/A (e.g. bolting, walls, clad vessels, structural steel, etc.).

3 Although the NUREG references a temperature gate of < 90 degrees C (200 degrees F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140 degrees F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The aging effect identified by PBNP (loss of material) for temperatures < 140 degrees F differs from that of the NUREG. That not withstanding, the Water Chemistry Control Program, which is credited

for managing the aging effects for all temperatures, will preclude the possibility of crack initiation and growth due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of the Chemistry program.

4 Plant specific program identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

5 Material/environment combination and/or aging effect not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

6 Program different than identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

7 There are no bolts with a specified minimum yield strength > 150 ksi in this system. Therefore, SCC is not an applicable aging effect/mechanism.

8 External aging effects are not applicable. Due to the way data is entered into the LRDB, the external environment of some components is listed as N/A (e.g. cladding, HX tubing, or other components that are entirely contained within another component).

9 AFW pump bearing coolers are integral to the bearing housing.

10 FE housing is CS but venturi is SS.

11 Internal portions of AFW turbine exhaust that are open to atmosphere.

12 Some components in this system experience a temperature below 200 degrees F, insufficient flow to support FAC, or operate less than 2% of the time. The components that fall in this category do not require aging management for FAC.

13 Some components are replaced on a specified frequency that precludes aging effects from resulting in loss of intended function. The Periodic Surveillance and Preventive Maintenance Program is used to replace these components.

14 AFW Pump turbine casing's environment is more closely related to Main Steam environments, since it is not addressed in Chapter VIII.G Aux Feedwater System.

15 Components in this grouping do not have flow velocities >10 fps, and therefore loss of material due to erosion is not an aging effect requiring management.

16 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not

subject to temperatures where change in material properties or cracking could occur (>95 degrees F). Therefore no aging management is required.

17 SCC is not a concern for this material/environment group, due to temperatures being <140 degrees F.

18 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are subject to temperatures where change in material properties or cracking could occur (>95 degrees F).

19 The Fuel Oil Chemistry Control Program is not necessary for managing the aging effects for a flame arrestor.

20 ISI inspections are not performed on this component, and therefore the ISI Program is not credited for managing the aging of this component.

21 Materials science supports loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The Water Chemistry Control Program is credited for managing the aging effects for all temperatures.

22 NUREG-1801 has loss of fracture toughness as an aging effect for this component. However, fluence levels for this component are below the threshold value, and therefore effects are not significant and do not require aging management.

23 NUREG-1801 credits the ISI Program for managing loss of material. PBNP does credit the ISI Program for managing cracking on this same component, and these inspections will identify loss of material/pitting, but only in the area of interest (at the weld). The Steam Generator Integrity Program is being included as it performs more general area inspections of the secondary side of the SGs. Previous visual inspections have confirmed no indications of loss of material.

24 This NUREG-1801 line item lists Loss of Material/Corrosion for the Aging Effect/Mechanism. This is interpreted to include the mechanisms of general and boric acid corrosion.

25 Tendon, loss of prestress NUREG-1801, line item 3.5.1-11/II.A1.3-b, is not addressed in this table. Refer to Section 4.0 on TLAAs.

26 No aging effects requiring management were identified for concrete (buried, indoor, or outdoor) and grout (except for Component Supports), however, concrete and grout is periodically monitored for potential degradation by an applicable license renewal program. See Appendix B for a discussion of the aging management programs used for concrete and grout.

27 Support (component or pipe) baseplates and their attachment to the structure (typically with embedded bolts or expansion anchors) are not within the scope of IWF and are considered

a part of the structure. However, for completeness, these items, including grout, are inspected when performing an IWF inspection. It is for this reason, that an ASME component support inspection will also be assigned against the Structures Monitoring Program.

28 The NUREG-1801 Volume I, line item 3.3.1-20, does not include the Control Building (Group 1 Structure), therefore, a comparable Group 3 Structure was chosen.

29 Doors that are assigned to the Structures Monitoring Program include those with the HELB function. Doors that are assigned to the Fire Protection Program include those with the fire or flood function. Note that some doors are common to both programs.

30 The Fire Barrier intended function is assigned to containment piping and electrical penetrations, fuel transfer tube, liner, and airlocks component types.

31 The fuel transfer tube is included with this component type (containment pressure boundary), therefore, the aging management program is appropriate.

32 Containment penetration sleeves, cracking/cyclic loading NUREG-1801, line item 3.5.1-2/II.A3.1-c, is not addressed in this table. Refer to Section 4.0 on TLAAs.

33 Crane, fatigue damage NUREG-1801, line item 3.3.1-3/VII.B.1-a, is not addressed in this table. Refer to Section 4.0 on TLAAs.

34 Consistent with NUREG-1801 for material, environment, aging effect and an additional AMP is credited.

35 Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter.

36 The material identified in this NUREG-1801 line item is stainless steel. The aging effects of stainless steel are the same as those for Cast Austenitic Stainless Steel at temperatures < 482 degrees F.

37 Unit 1 inspection port bolting has been identified by Westinghouse as being fatigue sensitive and needing replacement every 12 years. The Periodic Surveillance and Preventive Maintenance Program will be used to replace this bolting on a 10 year frequency.

38 The Unit 2 Steam Generators were designed and fabricated to eliminate the need for certain Section XI weld examinations. The Unit 2 transition cones are fabricated such that the girth welds are not at the discontinuity, and therefore Section XI does not require these welds to be periodically inspected. The steam nozzles were also fabricated integral to the elliptical head, and therefore there is no steam nozzle weld to inspect.

39 The One-Time Inspection is only for the letdown orifices, which is in response to NRC IN 98-045, “Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds.”

40 The Fuel Oil Chemistry Control Program includes provisions for performing tests/inspections for detecting tank wall loss.

41 In some cases where the Water Chemistry Control Program is not a viable option and aging effects are not expected to be significant, the One-Time Inspection Program alone is credited for managing aging effects. The One-Time Inspection Program has provisions to increase frequency of inspections based on the results of the first inspection.

Section 3.1 References

1. WCAP-14575-A, Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components, December, 2000.
2. WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Internals, March, 2001.
3. WCAP-14574-A, License Renewal Evaluation: Aging Management Evaluation for Pressurizers, December, 2000.
4. WCAP-15029-P-A, Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions November 1998.

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.

- Safety Injection System (Section 2.3.2.1)
- Containment Spray System (Section 2.3.2.2)
- Residual Heat Removal System (Section 2.3.2.3)
- Containment Isolation Components System (Section 2.3.2.4)

Table 3.2.1, Summary of Aging Management Evaluations in Chapter V of NUREG-1801 for Engineered Safety Features, provides the summary of the programs evaluated in NUREG-1801 for the Engineered Safety Features component groups that are utilized in license renewal.

This table uses the format described in Section 3.0 above. Note that this table only includes those component groups that are applicable to a PWR.

3.2.2 Results

The following tables summarize the results of the aging management review for systems in the Engineered Safety Features system group.

Table 3.2.2-1, Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Table 3.2.2-2, Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Table 3.2.2-3, Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Table 3.2.2-4, Engineered Safety Features - Containment Isolation Components System - Summary of Aging Management Evaluation

The materials that specific components are fabricated from, the environments to which components are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above systems in the following subsections of Section 3.2.2.1, Materials, Environment, Aging Effects Requiring Management and Aging Management Programs:

Section 3.2.2.1.1, Safety Injection System

Section 3.2.2.1.2, Containment Spray System

Section 3.2.2.1.3, Residual Heat Removal System

Section 3.2.2.1.4, Containment Isolation Components System

3.2.2.1 Materials, Environment, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Safety Injection System

Materials

The materials of construction for the Safety Injection System are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Cast Iron
- Stainless Steel

Environment

The Safety Injection System components are exposed to the following environments:

- Air and Gas (Internal)
- Borated Water Leaks (External)
- Concrete (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Treated Water - Borated, T<140°F (Internal)
- Treated Water - Borated, T>140°F (Internal)
- Treated Water - Other (Stagnant) (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Safety Injection System, require management:

- Cracking due to SCC

- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Safety Injection System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.2.2.1.2 Containment Spray System

Materials

The materials of construction for the Containment Spray System are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Cast Iron
- Stainless Steel

Environment

The Containment Spray System components are exposed to the following environments:

- Air and Gas
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Treated Water - Borated, T<140°F (Internal)
- Treated Water - Other (Stagnant) (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Containment Spray System, require management:

- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Spray System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.2.2.1.3 Residual Heat Removal System

Materials

The materials of construction for the Residual Heat Removal System are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Cast Iron
- Stainless Steel

Environment

The Residual Heat Removal System components are exposed to the following environments:

- Air and Gas - Wetted, T<140°F (Internal)
- Borated Water Leaks (External)
- Concrete (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Oil and Fuel Oil (Internal)
- Treated Water - Borated, T<140°F (Internal)
- Treated Water - Borated, T>140°F (Internal)
- Treated Water - Other (Stagnant) (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Residual Heat Removal System, require management:

- Cracking due to SCC
- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Residual Heat Removal System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.2.2.1.4 Containment Isolation Components System

Materials

The materials of construction for the Containment Isolation Components System are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Stainless Steel

Environment

The Containment Isolation Components System components are exposed to the following environments:

- Air and Gas
- Borated Water Leaks (External)
- Containment (External)

- Indoor - No Air Conditioning (External)
- Treated Water - Other (Stagnant) (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Containment Isolation Components System, require management:

- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Isolation Components System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.2.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

NUREG-1801 Volume 1 Tables provide the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Engineered Safety Features, those programs are addressed in the following sections.

3.2.2.2.1 Cumulative Fatigue Damage

Fatigue is a 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 separately in Section 4.3.

3.2.2.2.2.1 Loss of Material Due to General Corrosion

Applicable to BWR Only

3.2.2.2.2.2 Loss of Material Due to General Corrosion

This line item was not used at PBNP, although PBNP does have carbon steel components in the ESF systems. Loss of material due to general corrosion is an applicable aging effect/mechanism. PBNP addresses this aging effect for external environments in Item Number 3.2.1-10, and credits the Systems Monitoring Program for aging management. Internal environments are addressed in Item Number 3.2.1-05 for loss of material due to pitting and crevice corrosion, since detection and prevention of these aging effects/mechanisms would also detect and prevent general corrosion. In these cases, the Water Chemistry Control Program and/or One-Time Inspection Program are credited.

3.2.2.2.3.1 **Local Loss of Material due to Pitting and Crevice Corrosion**

Applicable to BWR Only

3.2.2.2.3.2 **Local Loss of Material due to Pitting and Crevice Corrosion**

Typically, pitting and crevice corrosion are managed at PBNP by the Water Chemistry Control Program and One-Time Inspection Program. This line item was also used for managing general corrosion and MIC.

PBNP's RWST is located indoors, not buried, and not susceptible to a wetted environment, and therefore is not subject to this aging effect/mechanism.

3.2.2.2.4 **Local Loss of Material due to Microbiologically Influenced Corrosion**

This line item was not used at PBNP, although PBNP does have components in the ESF systems that are subject to MIC. Internal environments are addressed in Item Number 3.2.1-05 for loss of material due to pitting and crevice corrosion, since detection and prevention of these aging effects/mechanisms would also detect and prevent MIC. In these cases, the Water Chemistry Control Program and/or One-Time Inspection Program are credited.

3.2.2.2.5 **Changes in Properties due to Elastomer Degradation**

Applicable to BWR Only

3.2.2.2.6 **Local Loss of Material due to Erosion**

The high pressure safety injection pumps are not used for normal charging at PBNP. Loss of material due to erosion of miniflow orifices is not applicable at PBNP.

3.2.2.2.7 **Buildup of Deposits due to Corrosion**

Applicable to BWR Only

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses (TLAA) identified below are associated with the Engineered Safety Features system components. The section of the LRA that contains the TLAA review results is indicated in parenthesis.

- Fatigue (Section 4.3, Metal Fatigue)
- Leak-Before-Break (Section 4.4.4, Leak-Before-Break)

3.2.3 Conclusion

The Engineered Safety Features piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Engineered Safety Features components are identified in the summaries in Section 3.2.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations 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 function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.2.1 Summary of Aging Management Evaluations in Chapter V of NUREG-1801 for Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-01	Piping, fittings, and valves in emergency core cooling system	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA (see [SRP] subsection 3.2.2.2.1)	Further evaluation documented in Section 3.2.2.2.1.
3.2.1-02	BWR only				
3.2.1-03	Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and emergency core cooling systems	Loss of material due to general corrosion	Plant specific	Yes, plant specific (see [SRP] subsection 3.2.2.2.2)	This line item was not used at PBNP. Further evaluation documented in Section 3.2.2.2.2.
3.2.1-04	BWR only				
3.2.1-05	Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and emergency core cooling systems	Loss of material due to pitting and crevice corrosion	Plant specific	Yes, plant specific (see [SRP] subsection 3.2.2.2.3.2)	Further evaluation documented in Section 3.2.2.2.3.2.
3.2.1-06	Containment isolation valves and associated piping	Loss of material due to microbiologically influenced corrosion	Plant specific	Yes, plant specific (see [SRP] subsection 3.2.2.2.4)	This line item was not used at PBNP. Further evaluation documented in Section 3.2.2.2.4.
3.2.1-07	BWR only				
3.2.1-08	High pressure safety injection (charging) pump miniflow orifice	Loss of material due to erosion	Plant specific	Yes, plant specific (see [SRP] subsection 3.2.2.2.6)	Not applicable at PBNP as SI pumps are not normally in use. Further evaluation documented in Section 3.2.2.2.6.
3.2.1-09	BWR only				

Table 3.2.1 Summary of Aging Management Evaluations in Chapter V of NUREG-1801 for Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-10	External surface of carbon steel components	Loss of material due to general corrosion	Plant specific	Yes, plant specific	The plant specific program credited for managing this aging effect, is the Systems Monitoring Program.
3.2.1-11	Piping and fittings of CASS in emergency core cooling system	Loss of fracture toughness due to thermal aging embrittlement	Thermal aging embrittlement of CASS	No	The CASS components in the ESF systems at PBNP are not subject to an environment that supports loss of fracture toughness due to thermal aging embrittlement. Those CASS components that are subject to this effect/mechanism are addressed in the Reactor Coolant System section as part of Class 1 Piping.
3.2.1-12	Components serviced by open-cycle cooling system	Local loss of material due to corrosion and/or buildup of deposit due to biofouling	Open-cycle cooling water system	No	PBNP does not utilize Open-Cycle Cooling Water in the ESF systems, and therefore this line item is not applicable.
3.2.1-13	Components serviced by closed-cycle cooling system	Loss of material due to general, pitting, and crevice corrosion	Closed-cycle cooling water system	No	In addition, PBNP credits the One-Time Inspection Program to verify the adequacy of the Closed-Cycle Cooling Water System Surveillance Program. Items V.A.6-c and V.D1.5-a address both tube-side and shell-side environments. For those ESF heat exchangers that have a treated water borated environment (tube-side of the HXs), the Water Chemistry Control Program and One-Time Inspection Program are credited.
3.2.1-14	BWR only				

Table 3.2.1 Summary of Aging Management Evaluations in Chapter V of NUREG-1801 for Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-15	Pumps, valves, piping, and fittings in containment spray and emergency core cooling systems	Crack initiation and growth due to SCC	Water chemistry	No	Although the NUREG references a temperature gate of <90°C (200°F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140°F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. Although the aging effect identified by PBNP (loss of material) for temperatures < 140°F differs from that of the NUREG, the Water Chemistry Control Program, which is credited for managing the aging effects for all temperatures, will preclude the possibility of cracking due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of the Water Chemistry Control Program.
3.2.1-16	BWR only				
3.2.1-17	Carbon steel components	Loss of material due to boric acid corrosion	Boric acid corrosion	No	PBNP credits the Boric Acid Corrosion Program which is consistent with NUREG-1801.
3.2.1-18	Closure bolting in high pressure or high temperature systems	Loss of material due to general corrosion, loss of preload due to stress relaxation, and crack initiation and growth due to cyclic loading or SCC	Bolting integrity	No	There are no bolts with a specified minimum yield strength > 150 ksi in the ESF Systems at PBNP. Therefore, SCC is not an applicable aging effect/mechanism. Loss of material is managed with the Bolting Integrity Program.

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	V.D1.1-d, V.D1.2-b, V.D1.4-c, V.D1.5-b, V.D1.7-a, V.D1.8-b, V.E.1-a	3.2.1-17	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a, (V.A.1-a)	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a, (V.A.1-a)	3.2.1-15	H, 3

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Heat Transfer	HX-Stainless Steel[a]	N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss of Heat Transfer due to Fouling	One-Time Inspection Program	(V.D1.1-a, V.D1.5-a)	(3.2.1-15)	H, 5
					Water Chemistry Control Program	(V.D1.1-a, V.D1.5-a)	(3.2.1-15)	H, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	H, 5
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	H, 5
	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	B
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	34

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Stainless Steel	N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.5-a	3.2.1-13	E, 6
					Water Chemistry Control Program	V.D1.5-a	3.2.1-13	E, 6
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	B
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	34
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a, V.D1.4-b	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a, V.D1.4-b	3.2.1-15	H, 3
Level Elements[b]	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	H, 3

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	H, 3
			Treated Water - Borated, T>140°F (Internal)	Cracking due to SCC	One-Time Inspection Program	V.D1.1-a	3.2.1-15	34, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	B, 3
			Treated Water - Borated, T>140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	H, 3

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Pump Casing	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.2-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.2-a	3.2.1-15	H, 3
Restricting Orifices	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3
					Water Chemistry Control Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3
	Restricts Flow	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3
					Water Chemistry Control Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			N/A (Internal)	None	None Required			2
		Stainless Steel	Concrete (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.7-b, V.D1.8-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.7-b, V.D1.8-a	3.2.1-15	H, 3
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.4-b)	(3.2.1-15)	36, H, 3
					Water Chemistry Control Program	(V.D1.4-b)	(3.2.1-15)	36, H, 3
			Treated Water - Borated, T>140°F (Internal)	Cracking due to SCC	One-Time Inspection Program	(V.D1.4-b)	(3.2.1-15)	36, 5
					Water Chemistry Control Program	(V.D1.4-b)	(3.2.1-15)	36, 5
				Loss Of Material	One-Time Inspection Program	(V.D1.4-b)	(3.2.1-15)	36, H, 3
					Water Chemistry Control Program	(V.D1.4-b)	(3.2.1-15)	36, H, 3

Table 3.2.2-1 Engineered Safety Features - Safety Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.4-b	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.4-b	3.2.1-15	H, 3
			Treated Water - Borated, T>140°F (Internal)	Cracking due to SCC	One-Time Inspection Program	V.D1.4-b	3.2.1-15	34, 3
					Water Chemistry Control Program	V.D1.4-b	3.2.1-15	B, 3
				Loss Of Material	One-Time Inspection Program	V.D1.4-b	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.4-b	3.2.1-15	H, 3

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.
b. Selected instruments were conservatively included within the scope of License Renewal. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for License Renewal review.

Table 3.2.2-2 Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	V.A.1-b, V.A.3-b, V.A.4-b, V.A.5-b, V.A.6-d, V.E.1-a	3.2.1-17	A
			N/A (Internal)	None	None Required			1
Eductor	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.A.1-c	3.2.1-15	H, 3
					Water Chemistry Control Program	V.A.1-c	3.2.1-15	H, 3
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2

Table 3.2.2-2 Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.A.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.A.1-a	3.2.1-15	H, 3
Heat Exchanger	Heat Transfer	HX-Stainless Steel[a]	N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss of Heat Transfer due to Fouling	One-Time Inspection Program	(V.D1.1-a, V.D1.5-a)	(3.2.1-15)	H, 5
					Water Chemistry Control Program	(V.D1.1-a, V.D1.5-a)	(3.2.1-15)	H, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(V.D1.5-a)	(3.2.1-13)	H, 5
					One-Time Inspection Program	(V.D1.5-a)	(3.2.1-13)	H, 5
	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	B
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	34

Table 3.2.2-2 Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Stainless Steel	N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.5-a	3.2.1-13	E, 6
					Water Chemistry Control Program	V.D1.5-a	3.2.1-13	E, 6
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	B
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	34
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.A.1-a, V.A.4-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.A.1-a, V.A.4-a	3.2.1-15	H, 3
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	4

Table 3.2.2-2 Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.A.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.A.1-a	3.2.1-15	H, 3
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	4
Pump Casing	Pressure Boundary	Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.3-a)	(3.2.1-15)	36, H, 3
					Water Chemistry Control Program	(V.A.3-a)	(3.2.1-15)	36, H, 3

Table 3.2.2-2   Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Restricting Orifices	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.A.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.A.1-a	3.2.1-15	H, 3
	Restricts Flow	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.A.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.A.1-a	3.2.1-15	H, 3
Spray Nozzle	Flow Control	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J

Table 3.2.2-2 Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			N/A (Internal)	None	None Required			2
		Stainless Steel	N/A (External)	None	None Required			8
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	4
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.4-a)	(3.2.1-15)	36, H, 3
					Water Chemistry Control Program	(V.A.4-a)	(3.2.1-15)	36, H, 3
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	F, 4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	F, 4

Table 3.2.2-2 Engineered Safety Features - Containment Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.A.4-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.A.4-a	3.2.1-15	H, 3
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	4

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	V.D1.1-d, V.D1.2-b, V.D1.4-c, V.D1.5-b, V.D1.7-a, V.D1.8-b, V.E.1-a	3.2.1-17	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Filters/Strainers	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	H, 3

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Provide Filtration	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	H, 3
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a, (V.A.1-a)	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a, (V.A.1-a)	3.2.1-15	H, 3
Heat Exchanger	Heat Transfer	HX-Stainless Steel[a]	N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss of Heat Transfer due to Fouling	One-Time Inspection Program	(V.D1.1-a, V.D1.5-a)	(3.2.1-15)	H, 5
					Water Chemistry Control Program	(V.D1.1-a, V.D1.5-a)	(3.2.1-15)	H, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	H, 5
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	H, 5

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	B
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	34
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	B
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	34
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.5-a	3.2.1-13	E, 6
					Water Chemistry Control Program	V.D1.5-a	3.2.1-13	E, 6

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Stainless Steel	Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	V.D1.5-a	3.2.1-13	B
					One-Time Inspection Program	V.D1.5-a	3.2.1-13	34
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a, V.D1.4-b	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a, V.D1.4-b	3.2.1-15	H, 3
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	35, 4
		Stainless Steel	Concrete (External)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	35, 4
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	H, 3
			Treated Water - Borated, T>140°F (Internal)	Cracking due to SCC	One-Time Inspection Program	V.D1.1-a	3.2.1-15	34, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	B, 3
				Loss Of Material	One-Time Inspection Program	V.D1.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	H, 3
Pump Casing	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	35, 4

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Pump Casing	Pressure Boundary	Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.2-a)	(3.2.1-15)	36, H, 3
					Water Chemistry Control Program	(V.D1.2-a)	(3.2.1-15)	36, H, 3
Restricting Orifices	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3
					Water Chemistry Control Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3
	Restricts Flow	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3
					Water Chemistry Control Program	V.D1.2-c, (V.A.1-a)	3.2.1-08, (3.2.1-15)	H, I, 3
Sump Screen	Provide Filtration	Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Containment (External)	None	None Required			J

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	35, 4
Thermowells	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.1-a	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.1-a	3.2.1-15	H, 3
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	35, 4
		Cast Austenitic Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.2.2-3 Engineered Safety Features - Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.4-b)	(3.2.1-15)	36, H, 3
					Water Chemistry Control Program	(V.D1.4-b)	(3.2.1-15)	36, H, 3
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	35, 4
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	V.D1.4-b	3.2.1-15	H, 3
					Water Chemistry Control Program	V.D1.4-b	3.2.1-15	H, 3
Valve Operator	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	35, 4

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

Table 3.2.2-4 Engineered Safety Features - Containment Isolation Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	V.E.1-a	3.2.1-17	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	V.E.2-a	3.2.1-18	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	V.E.1-b	3.2.1-10	4

Table 3.2.2-4 Engineered Safety Features - Containment Isolation Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	V.C.1-b	3.2.1-05	4
					Water Chemistry Control Program	V.C.1-b	3.2.1-05	4
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	F, 4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	F, 4

Table 3.2.2-4 Engineered Safety Features - Containment Isolation Components System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Notes for Tables 3.2.2-1 through 3.2.2-4

A Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP has exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP has exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect but a different AMP is credited.

F Material not in NUREG-1801 for this component.

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

I Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-specific notes:

1 The CS Component asset was created to manage Boric Acid wastage of external surfaces only (for any carbon steel, low alloy steel, or cast iron component, including bolting), and therefore internal environments for this asset are not applicable. All other internal and external aging effects are identified separately under the specific component type.

2 Internal aging effects are not applicable. Due to the way data is entered into the LRDB, the internal environment of some components is listed as N/A (e.g. bolting, walls, clad vessels, structural steel, etc.).

3 Although the NUREG references a temperature gate of < 90 degrees C (200 degrees F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140 degrees F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The aging effect identified by PBNP (loss of material) for temperatures < 140 degrees F differs from that of the NUREG. That not withstanding, the Water Chemistry Control Program, which is credited

for managing the aging effects for all temperatures, will preclude the possibility of crack initiation and growth due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of the Chemistry program.

4 Plant specific program identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

5 Material/environment combination and/or aging effect not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

6 Program different than identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

7 There are no bolts with a specified minimum yield strength > 150 ksi in this system. Therefore, SCC is not an applicable aging effect/mechanism.

8 External aging effects are not applicable. Due to the way data is entered into the LRDB, the external environment of some components is listed as N/A (e.g. cladding, HX tubing, or other components that are entirely contained within another component).

9 AFW pump bearing coolers are integral to the bearing housing.

10 FE housing is CS but venturi is SS.

11 Internal portions of AFW turbine exhaust that are open to atmosphere.

12 Some components in this system experience a temperature below 200 degrees F, insufficient flow to support FAC, or operate less than 2% of the time. The components that fall in this category do not require aging management for FAC.

13 Some components are replaced on a specified frequency that precludes aging effects from resulting in loss of intended function. The Periodic Surveillance and Preventive Maintenance Program is used to replace these components.

14 AFW Pump turbine casing's environment is more closely related to Main Steam environments, since it is not addressed in Chapter VIII.G Aux Feedwater System.

15 Components in this grouping do not have flow velocities >10 fps, and therefore loss of material due to erosion is not an aging effect requiring management.

16 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not subject to temperatures where change in material properties or cracking could occur (>95 degrees F). Therefore no aging management is required.

17 SCC is not a concern for this material/environment group, due to temperatures being <140 degrees F.

18 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are subject to temperatures where change in material properties or cracking could occur (>95 degrees F).

19 The Fuel Oil Chemistry Control Program is not necessary for managing the aging effects for a flame arrestor.

20 ISI inspections are not performed on this component, and therefore the ISI Program is not credited for managing the aging of this component.

21 Materials science supports loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The Water Chemistry Control Program is credited for managing the aging effects for all temperatures.

22 NUREG-1801 has loss of fracture toughness as an aging effect for this component. However, fluence levels for this component are below the threshold value, and therefore effects are not significant and do not require aging management.

23 NUREG-1801 credits the ISI Program for managing loss of material. PBNP does credit the ISI Program for managing cracking on this same component, and these inspections will identify loss of material/pitting, but only in the area of interest (at the weld). The Steam Generator Integrity Program is being included as it performs more general area inspections of the secondary side of the SGs. Previous visual inspections have confirmed no indications of loss of material.

24 This NUREG-1801 line item lists Loss of Material/Corrosion for the Aging Effect/Mechanism. This is interpreted to include the mechanisms of general and boric acid corrosion.

25 Tendon, loss of prestress NUREG-1801, line item 3.5.1-11/II.A1.3-b, is not addressed in this table. Refer to Section 4.0 on TLAAs.

26 No aging effects requiring management were identified for concrete (buried, indoor, or outdoor) and grout (except for Component Supports), however, concrete and grout is periodically monitored for potential degradation by an applicable license renewal program. See Appendix B for a discussion of the aging management programs used for concrete and grout.

27 Support (component or pipe) baseplates and their attachment to the structure (typically with embedded bolts or expansion anchors) are not within the scope of IWF and are considered a part of the structure. However, for completeness, these items, including grout, are inspected when performing an IWF inspection. It is for this reason, that an ASME component support inspection will also be assigned against the Structures Monitoring Program.

28 The NUREG-1801 Volume I, line item 3.3.1-20, does not include the Control Building (Group 1 Structure), therefore, a comparable Group 3 Structure was chosen.

29 Doors that are assigned to the Structures Monitoring Program include those with the HELB function. Doors that are assigned to the Fire Protection Program include those with the fire or flood function. Note that some doors are common to both programs.

30 The Fire Barrier intended function is assigned to containment piping and electrical penetrations, fuel transfer tube, liner, and airlocks component types.

31 The fuel transfer tube is included with this component type (containment pressure boundary), therefore, the aging management program is appropriate.

32 Containment penetration sleeves, cracking/cyclic loading NUREG-1801, line item 3.5.1-2/II.A3.1-c, is not addressed in this table. Refer to Section 4.0 on TLAAs.

33 Crane, fatigue damage NUREG-1801, line item 3.3.1-3/VII.B.1-a, is not addressed in this table. Refer to Section 4.0 on TLAAs.

34 Consistent with NUREG-1801 for material, environment, aging effect and an additional AMP is credited.

35 Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter.

36 The material identified in this NUREG-1801 line item is stainless steel. The aging effects of stainless steel are the same as those for Cast Austenitic Stainless Steel at temperatures < 482 degrees F.

37 Unit 1 inspection port bolting has been identified by Westinghouse as being fatigue sensitive and needing replacement every 12 years. The Periodic Surveillance and Preventive Maintenance Program will be used to replace this bolting on a 10 year frequency.

38 The Unit 2 Steam Generators were designed and fabricated to eliminate the need for certain Section XI weld examinations. The Unit 2 transition cones are fabricated such that the girth welds are not at the discontinuity, and therefore Section XI does not require these welds to be periodically inspected. The steam nozzles were also fabricated integral to the elliptical head, and therefore there is no steam nozzle weld to inspect.

39 The One-Time Inspection is only for the letdown orifices, which is in response to NRC IN 98-045, “Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds.”

40 The Fuel Oil Chemistry Control Program includes provisions for performing tests/inspections for detecting tank wall loss.

41 In some cases where the Water Chemistry Control Program is not a viable option and aging effects are not expected to be significant, the One-Time Inspection Program alone is credited for managing aging effects. The One-Time Inspection Program has provisions to increase frequency of inspections based on the results of the first inspection.

3.3 Aging Management of Auxiliary Systems

3.3.1 Introduction

This section provides the results of the aging management review for those components identified in Section 2.3.3, Auxiliary Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section, are described in the indicated sections.

- Chemical and Volume Control System (Section 2.3.3.1)
- Component Cooling Water System (Section 2.3.3.2)
- Spent Fuel Cooling System (Section 2.3.3.3)
- Waste Disposal System (Section 2.3.3.4)
- Service Water System (Section 2.3.3.5)
- Fire Protection System (Section 2.3.3.6)
- Heating Steam System (Section 2.3.3.7)
- Emergency Power System (Section 2.3.3.8)
- Containment Ventilation System (Section 2.3.3.9)
- Essential Ventilation System (Section 2.3.3.10)
- Treated Water System (Section 2.3.3.11)
- Circulating Water System (Section 2.3.3.12)
- Fuel Handling System (Section 2.3.3.13)
- Plant Sampling System (Section 2.3.3.14)
- Plant Air System (Section 2.3.3.15)
- Containment Hydrogen Detectors and Recombiner System (Section 2.3.3.16)

Table 3.3.1, Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems, provides the summary of the programs evaluated in NUREG-1801 for the Auxiliary Systems component groups that are relied on for license renewal.

This table uses the format described in Section 3.0 above. Note that this table only includes those component groups that are applicable to a PWR.

3.3.2 Results

The following tables summarize the results of the aging management review for systems in the Auxiliary Systems group:

Table 3.3.2-1, Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Table 3.3.2-2, Auxiliary Systems - Component Cooling Water System - Summary of Aging Management Evaluation

Table 3.3.2-3, Auxiliary Systems - Spent Fuel Cooling System - Summary of Aging Management Evaluation

Table 3.3.2-4, Auxiliary Systems - Waste Disposal System - Summary of Aging Management Evaluation

Table 3.3.2-5, Auxiliary Systems - Service Water System - Summary of Aging Management Evaluation

Table 3.3.2-6, Auxiliary Systems - Fire Protection System - Summary of Aging Management Evaluation

Table 3.3.2-7, Auxiliary Systems - Emergency Power System - Summary of Aging Management Evaluation

Table 3.3.2-8, Auxiliary Systems - Containment Ventilation System - Summary of Aging Management Evaluation

Table 3.3.2-9, Auxiliary Systems - Essential Ventilation System - Summary of Aging Management Evaluation

Table 3.3.2-10, Auxiliary Systems - Plant Sampling System - Summary of Aging Management Evaluation

Table 3.3.2-11, Auxiliary Systems - Plant Air System - Summary of Aging Management Evaluation

Table 3.3.2-12, Auxiliary Systems - Containment Hydrogen Detectors and Recombiner System - Summary of Aging Management Evaluation

Table 3.3.2-13, Auxiliary Systems - Circulating Water System - Summary of Aging Management Evaluation

Table 3.3.2-14, Auxiliary Systems - Treated Water System - Summary of Aging Management Evaluation

Table 3.3.2-15, Auxiliary Systems - Heating Steam System - Summary of Aging Management Evaluation

Table 3.3.2-16, Auxiliary Systems - Fuel Handling System - Summary of Aging Management Evaluation

The materials that specific components are fabricated from, the environments to which components are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above systems in the following subsections of Section 3.3.2.1, Materials, Environment, Aging Effects Requiring Management and Aging Management Programs:

Section 3.3.2.1.1, Chemical and Volume Control System

Section 3.3.2.1.2, Component Cooling Water System

Section 3.3.2.1.3, Spent Fuel Cooling System

Section 3.3.2.1.4, Waste Disposal System

Section 3.3.2.1.5, Service Water System

Section 3.3.2.1.6, Fire Protection System

Section 3.3.2.1.7, Emergency Power System

Section 3.3.2.1.8, Containment Ventilation System

Section 3.3.2.1.9, Essential Ventilation System

Section 3.3.2.1.10, Plant Sampling System

Section 3.3.2.1.11, Plant Air System

Section 3.3.2.1.12, Containment Hydrogen Detectors and Recombiner System

Section 3.3.2.1.13, Circulating Water System

Section 3.3.2.1.14, Treated Water System

Section 3.3.2.1.15, Heating Steam System

Section 3.3.2.1.16, Fuel Handling System

3.3.2.1 Materials, Environment, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Chemical and Volume Control System

Materials

The materials of construction for the Chemical and Volume Control System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Stainless Steel

Environment

The Chemical and Volume Control System components are exposed to the following environments:

- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Treated Water - Borated, T<140°F (Internal)
- Treated Water - Borated, T>140°F (Internal)
- Treated Water - Other (Internal)
- Treated Water - Other (Stagnant) (Internal)
- Treated Water - Primary, T<140°F (Internal)
- Treated Water - Primary, 140°F<T<480°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Chemical and Volume Control System, require management:

- Cracking due to SCC
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Chemical and Volume Control System components:

- Bolting Integrity Program

- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.3.2.1.2 Component Cooling Water System

Materials

The materials of construction for the Component Cooling Water System components are:

- Carbon/Low Alloy Steel
- Cast Iron
- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Stainless Steel

Environment

The Component Cooling Water System components are exposed to the following environments:

- Air and Gas - Wetted, T<140°F (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Raw Water (Velocity) (Internal)
- Treated Water - Other (Internal)
- Treated Water - Other (Stagnant) (Internal)
- Treated Water - Other (Velocity) (Internal)
- Treated Water - Primary, T>480°F (Internal)
- Treated Water - Primary, 140°F<T<480°F (Internal)
- Treated Water - Secondary, T>120°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Component Cooling Water System, require management:

- Cracking due to IGA/IGSCC
- Cracking due to SCC
- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Component Cooling Water System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Open-Cycle Cooling (Service) Water System Surveillance Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.3.2.1.3 **Spent Fuel Cooling System**

Materials

The materials of construction for the Spent Fuel Cooling System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Stainless Steel

Environment

The Spent Fuel Cooling System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - No Air Conditioning (External)
- Raw Water (Internal)

- Treated Water - Borated, T<140°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Spent Fuel Cooling System, require management:

- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Spent Fuel Cooling System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- One-Time Inspection Program
- Open-Cycle Cooling (Service) Water System Surveillance Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.3.2.1.4 **Waste Disposal System**

Materials

The materials of construction for the Waste Disposal System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Copper Alloy (Zn > 15%)
- Stainless Steel

Environment

The Waste Disposal System components are exposed to the following environments:

- Air and Gas - Wetted, T<140°F (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Raw Water Drainage (Internal)

- Treated Water - Borated, T<140°F (Internal)
- Treated Water - Other (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Waste Disposal System, require management:

- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Waste Disposal System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.3.2.1.5 Service Water System

Materials

The materials of construction for the Service Water System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Cast Iron
- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Glass
- Neoprene
- Stainless Steel

Environment

The Service Water System components are exposed to the following environments:

- Borated Water Leaks (External)
- Buried (External)
- Containment (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Indoor - Wetted (External)
- Raw Water (Internal)
- Raw Water (Stagnant) (Internal)
- Raw Water (Submerged) (External)
- Raw Water (Velocity) (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Service Water System, require management:

- Change in Material Properties and Cracking
- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Service Water System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Buried Services Monitoring Program
- Fire Protection Program
- Open-Cycle Cooling (Service) Water System Surveillance Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program

3.3.2.1.6 Fire Protection System

Materials

The materials of construction for the Fire Protection System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Cast Iron
- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Glass
- Neoprene
- Stainless Steel

Environment

The Fire Protection System components are exposed to the following environments:

- Air and Gas (Internal)
- Air and Gas - Wetted, T<140°F (Internal)
- Borated Water Leaks (External)
- Buried (External)
- Concrete (External)
- Containment (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Oil and Fuel Oil (Internal)
- Oil and Fuel Oil - Pooling (Internal)
- Outdoor (External)
- Raw Water (Stagnant) (Internal)
- Treated Water - Other (Stagnant) (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Fire Protection System, require management:

- Change in Material Properties and Cracking
- Cracking due to SCC
- Loss of Heat Transfer due to Fouling
- Loss of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Fire Protection System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Buried Services Monitoring Program
- Fire Protection Program
- Fuel Oil Chemistry Control Program
- One-Time Inspection Program
- Systems Monitoring Program

3.3.2.1.7 Emergency Power System

Materials

The materials of construction for the Emergency Power System components are:

- Aluminum
- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Cast Iron
- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Elastomer
- Glass
- Neoprene

- Plastic Pipe
- Stainless Steel

Environment

The Emergency Power System components are exposed to the following environments:

- Air and Gas (Internal)
- Air and Gas - Wetted, T<140°F (Internal)
- Buried (External)
- Concrete (External)
- Indoor - No Air Conditioning (External)
- Oil and Fuel Oil (Internal)
- Oil and Fuel Oil - Pooling (Internal)
- Outdoor (External)
- Raw Water (Internal)
- Treated Water - Other (Stagnant) (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Emergency Power System, require management:

- Change in Material Properties and Cracking
- Change in Material Properties due to Elevated Temperature
- Cracking due to Elevated Temperature
- Cracking due to SCC
- Cracking due to Ultraviolet Radiation and Ozone
- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Emergency Power System components:

- Bolting Integrity Program
- Buried Services Monitoring Program

- Closed-Cycle Cooling Water System Surveillance Program
- Fuel Oil Chemistry Control Program
- One-Time Inspection Program
- Open-Cycle Cooling (Service) Water System Surveillance Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Tank Internal Inspection Program

3.3.2.1.8 **Containment Ventilation System**

Materials

The materials of construction for the Containment Ventilation System components are:

- Carbon/Low Alloy Steel
- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Elastomer
- Stainless Steel

Environment

The Containment Ventilation System components are exposed to the following environments:

- Air and Gas (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Indoor - Wetted (External)
- Raw Water (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Containment Ventilation System, require management:

- Change in Material Properties due to Elevated Temperature
- Cracking due to Elevated Temperature

- Cracking due to Ultraviolet Radiation and Ozone
- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Ventilation System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Open-Cycle Cooling (Service) Water System Surveillance Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program

3.3.2.1.9 Essential Ventilation System

Materials

The materials of construction for the Essential Ventilation System components are:

- Carbon/Low Alloy Steel
- Cast Iron
- Copper Alloy (Zn < 15%)
- Elastomer
- Glass
- Stainless Steel

Environment

The Essential Ventilation System components are exposed to the following environments:

- Air and Gas (Internal)
- Air and Gas - Wetted, T<140°F (Internal)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Raw Water (Internal)

- Raw Water (Velocity) (Internal)
- Treated Water - Other (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Essential Ventilation System, require management:

- Change in Material Properties due to Elevated Temperature
- Cracking due to Elevated Temperature
- Cracking due to Ultraviolet Radiation and Ozone
- Loss of Heat Transfer due to Fouling
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Essential Ventilation System components:

- Bolting Integrity Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Open-Cycle Cooling (Service) Water System Surveillance Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program

3.3.2.1.10 **Plant Sampling System**

Components requiring aging management within the Plant Sampling System are addressed in the following systems; Class 1 Piping/Components (Section 3.1.2.1.1), Residual Heat Removal System (Section 3.2.2.1.3), Chemical and Volume Control System (Section 3.3.2.1.1), and Component Cooling Water System (Section 3.3.2.1.2).

3.3.2.1.11 **Plant Air System**

Materials

The materials of construction for the Plant Air System components are:

- Carbon/Low Alloy Steel
- Cast Iron

- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Plastic Pipe
- Stainless Steel

Environment

The Plant Air System components are exposed to the following environments:

- Air and Gas (Internal)
- Air and Gas - Wetted, T<140°F (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)

Aging Effects Requiring Management

The following aging effects, associated with the Plant Air System, require management:

- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Plant Air System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program

3.3.2.1.12 Containment Hydrogen Detectors and Recombiner System

Materials

The materials of construction for the Containment Hydrogen Detectors and Recombiner System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Stainless Steel

Environment

The Containment Hydrogen Detectors and Recombiner System components are exposed to the following environments:

- Air and Gas (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)

Aging Effects Requiring Management

The following aging effects, associated with the Containment Hydrogen Detectors and Recombiner System, require management:

- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Hydrogen Detectors and Recombiner System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Systems Monitoring Program

3.3.2.1.13 Circulating Water System

Materials

The materials of construction for the Circulating Water System components are:

- Carbon/Low Alloy Steel
- Cast Iron
- Neoprene
- Plastic Pipe
- Stainless Steel

Environment

The Circulating Water System components are exposed to the following environments:

- Indoor - No Air Conditioning (External)
- Raw Water (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Circulating Water System, require management:

- Change in Material Properties and Cracking
- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Circulating Water System components:

- Bolting Integrity Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program

3.3.2.1.14 Treated Water System

Materials

The materials of construction for the Treated Water System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Copper Alloy (Zn < 15%)
- Stainless Steel

Environment

The Treated Water System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - No Air Conditioning (External)
- Raw Water Drainage (Internal)
- Treated Water - Other (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Treated Water System, require management:

- Loss Of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Treated Water System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program

3.3.2.1.15 Heating Steam System

Materials

The materials of construction for the Heating Steam System components are:

- Carbon/Low Alloy Steel
- Cast Iron
- Copper Alloy (Zn < 15%)
- Stainless Steel

Environment

The Heating Steam System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - No Air Conditioning (External)
- Treated Water - Secondary, T>120°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Heating Steam System, require management:

- Cracking due to SCC
- Loss Of Material
- Loss of Material due to FAC/Erosion-Corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the Heating Steam System components:

- Bolting Integrity Program

- Boric Acid Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.3.2.1.16 Fuel Handling System

Components requiring aging management within the Fuel Handling System are addressed in the Spent Fuel Cooling System (Section 3.3.2.1.3), the Primary Auxiliary Building Structure (Section 3.5.2.1.6), and the Containment Unit 1/2 Building Structure (Section 3.5.2.1.1).

3.3.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

NUREG-1801 Volume 1 Tables provide the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Auxiliary Systems, those programs are addressed in the following sections.

3.3.2.2.1.1 Loss of Material due to General, Pitting, and Crevice Corrosion

NUREG-1801 Vol. 2 items identified in Item Number 3.3.1-01 (A3.2-a, A3.3-a, and A3.5-a) relate to carbon steel components with elastomer linings. The PBNP Spent Fuel Cooling System does not contain any carbon steel components with elastomer linings. All of the components in the PBNP Spent Fuel Cooling System are stainless steel. Due to the absence of this material/environment combination in the Auxiliary System section, PBNP used Item Number 3.2.1-15 (ESF) to address aging effects of these components. The Water Chemistry Control Program is credited with managing these aging effects. The One-Time Inspection Program is also used to verify the effectiveness of water chemistry control. The use of these programs is consistent with the requirements of Item Number 3.3.1-01.

3.3.2.2.1.2 Loss of Material due to General, Pitting, and Crevice Corrosion

Same as 3.3.2.2.1.1.

3.3.2.2.2 Hardening and Cracking or Loss of Strength due to Elastomer Degradation or Loss of Material due to Wear

The Spent Fuel Cooling System at PBNP contains no components that are elastomer lined, however, the elastomer seals for the SFP gates are included here. The Periodic Surveillance and Preventive Maintenance Program is credited for managing the hardening and cracking.

For ventilation systems at PBNP, the Periodic Surveillance and Preventive Maintenance Program is credited for managing the hardening and cracking, or loss of strength aging effects, where applicable. In many cases, the temperature, radiation, and UV exposure do not support these aging effects, and therefore no aging management is required. (NOTE: PBNP refers to hardening and loss of strength as change in material properties.) Loss of material due to wear is judged to be event/design driven, and therefore is not an aging effect requiring management.

3.3.2.2.3 Cumulative Fatigue Damage

Fatigue is a 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 separately in Section 4.3.

3.3.2.2.4 Crack Initiation and Growth due to Cracking or Stress Corrosion Cracking

Although this NUREG references a temperature gate of <90°C (200°F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140°F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. Although the aging effect identified by PBNP (loss of material) for temperatures < 140°F differs from that of this NUREG, the Water Chemistry Control Program, which is credited for managing the aging effects for all temperatures, will preclude the possibility of cracking due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of water chemistry control.

3.3.2.2.5 Loss of Material due to General, Microbiologically Influenced, Pitting, and Crevice Corrosion

For the internal environments of applicable Auxiliary Systems, the Periodic Surveillance and Preventive Maintenance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, One-Time Inspection Program, Fire Protection Program, and Tank Internal Inspection Program are credited for managing these aging effects.

For the external surfaces of all carbon steel components in PBNP Auxiliary Systems, the Systems Monitoring Program will be credited for managing the aging effect of loss of material. In some cases, the Open-Cycle Cooling (Service) Water System Surveillance Program or the Fire Protection Program is credited to augment the Systems Monitoring Program for managing external aging effects. Closure bolting is addressed in Item Number 3.3.1-24.

3.3.2.2.6 Loss of Material due to General, Galvanic, Pitting, and Crevice Corrosion

The aging effects of components within the Reactor Coolant Pump Oil Collection sub-system at PBNP, will be managed by the One-Time Inspection Program.

3.3.2.2.7 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Biofouling

The Fuel Oil Chemistry Control Program is credited with managing the applicable aging effects in the PBNP fuel oil systems. The One-Time Inspection Program is also used to verify the adequacy of the Fuel Oil Chemistry Program in managing these aging effects.

3.3.2.2.1.2 Loss of Material due to General, Pitting, and Crevice Corrosion

Applicable to BWR Only

3.3.2.2.9 Crack Initiation and Growth due to Stress Corrosion Cracking and Cyclic Loading

Although this NUREG references a temperature gate of <90°C (200°F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140°F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. Although the aging effect identified by PBNP (loss of material) for temperatures < 140°F differs from that of this NUREG, the Water Chemistry Control Program, which is credited for managing the aging effects for all temperatures, will preclude the possibility of cracking due to SCC. In some cases, the Closed-Cycle Cooling Water System Surveillance Program is credited, which includes water chemistry controls for closed-cycle cooling water. In all cases, the One-Time Inspection Program is also credited to verify the adequacy of water chemistry control.

3.3.2.2.10 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

This material, Boral, is not used at PBNP, therefore an Aging Management Program is not required. Line item 3.3.1-12 dealing with Boraflex is applicable to PBNP.

3.3.2.2.11 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

The Buried Services Monitoring Program is credited for managing these aging effects for buried components at PBNP.

External surfaces of buried components are visually examined during maintenance activities (inspections of opportunity). No evidence of age-related degradation has been detected from inspections performed to date.

Ground water/lake water at PBNP is analyzed periodically and analyses performed to date confirm that the water is non-aggressive.

3.3.2.3 Time-Limited Aging Analysis

The time-limited aging analyses (TLAA) identified below are associated with the Auxiliary Systems components. The section of the LRA that contains the TLAA review results is indicated in parenthesis.

- Fatigue (Section 4.3, Metal Fatigue)

3.3.3 Conclusion

The Auxiliary 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 Auxiliary Systems components are identified in the summaries in Section 3.3.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the Auxiliary System components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-01	Components in spent fuel pool cooling and cleanup	Loss of material due to general, pitting, and crevice corrosion	Water chemistry and one-time inspection	Yes, detection of aging effects is to be further evaluated (see [SRP] subsections 3.3.2.2.1.1 and 3.3.2.2.1.2)	Further evaluation documented in Section 3.3.2.2.1.1 and Section 3.3.2.2.1.2.
3.3.1-02	Linings in spent fuel pool cooling and cleanup system; seals and collars in ventilation systems	Hardening, cracking and loss of strength due to elastomer degradation; loss of material due to wear	Plant specific	Yes, plant specific (see [SRP] subsection 3.3.2.2.2)	Further evaluation documented in Section 3.3.2.2.2.
3.3.1-03	Components in load handling, chemical and volume control system (PWR), and reactor water cleanup and shutdown cooling systems (older BWR)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA (see [SRP] subsection 3.3.2.2.3)	Further evaluation documented in Section 3.3.2.2.3.
3.3.1-04	Heat exchangers in reactor water cleanup system (BWR); high pressure pumps in chemical and volume control system (PWR)	Crack initiation and growth due to SCC or cracking	Plant specific	Yes, plant specific (see [SRP] subsection 3.3.2.2.4)	Further evaluation documented in Section 3.3.2.2.4.
3.3.1-05	Components in ventilation systems, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components	Loss of material due to general, pitting, and crevice corrosion, and MIC	Plant specific	Yes, plant specific (see [SRP] subsection 3.3.2.2.5)	Further evaluation documented in Section 3.3.2.2.5.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-06	Components in reactor coolant pump oil collect system of fire protection	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-time inspection	Yes, detection of aging effects is to be further evaluated (see [SRP] subsection 3.3.2.2.6)	Further evaluation documented in Section 3.3.2.2.6.
3.3.1-07	Diesel fuel oil tanks in diesel fuel oil system and emergency diesel generator system	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel oil chemistry and one-time inspection	Yes, detection of aging effects is to be further evaluated (see [SRP] subsection 3.3.2.2.7)	Further evaluation documented in Section 3.3.2.2.7.
3.3.1-08	BWR only				
3.3.1-09	Heat exchangers in chemical and volume control system	Crack initiation and growth due to SCC and cyclic loading	Water chemistry and a plant-specific verification program	Yes, plant specific (see [SRP] subsection 3.3.2.2.9)	Further evaluation documented in Section 3.3.2.2.9.
3.3.1-10	Neutron absorbing sheets in spent fuel storage racks	Reduction of neutron absorbing capacity and loss of material due to general corrosion (Boral, boron steel)	Plant specific	Yes, plant specific (see [SRP] subsection 3.3.2.2.10)	Further evaluation documented in Section 3.3.2.2.10.
3.3.1-11	New fuel rack assembly	Loss of material due to general, pitting, and crevice corrosion	Structures monitoring	No	The Structures Monitoring Program is credited with managing the aging effects of loss of material due to general, pitting, and crevice corrosion.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-12	Neutron absorbing sheets in spent fuel storage racks	Reduction of neutron absorbing capacity due to Boraflex degradation	Boraflex monitoring	No	Reduction of neutron absorbing capacity due to Boraflex degradation is an aging effect managed by the Boraflex Monitoring Program. The NUREG-1801 Program Description states that "Certain accelerated samples are tested every two years." The Boraflex Monitoring Program does not perform these tests on a two year frequency. However, the testing done on a minimum frequency of once every five years includes panels with accelerated exposure. The results of the Boraflex areal density testing and Boraflex panel blackness testing are evaluated as part of the Boraflex Monitoring Program to determine if a change in test frequency or methodology is warranted.
3.3.1-13	Spent fuel storage racks and valves in spent fuel pool cooling and cleanup	Crack initiation and growth due to stress corrosion cracking	Water chemistry	No	The material identified in the NUREG-1801 Vol. 2 line item of 3.3.1-13 (A3.3-b) is carbon steel with stainless steel cladding. All valves in the PBNP Spent Fuel Cooling System are stainless steel, and therefore Line Item 3.2.1-15 was used to address these valves and applicable aging effects. The stainless steel of the spent fuel storage racks (A2.1-c) is consistent with this line item. The Water Chemistry Control Program is credited with managing these aging effects. The One-Time Inspection Program is also used to verify the effectiveness of water chemistry control. The use of these programs is consistent with the requirements of Line Item 3.3.1-13.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-14	Closure bolting and external surfaces of carbon steel and low-alloy steel components	Loss of material due to boric acid corrosion	Boric acid corrosion	No	Consistent with NUREG-1801. The Boric Acid Corrosion Program is credited with managing the aging effect of loss of material due to boric acid wastage on the external surfaces of carbon/low alloy steel components (including closure bolting). Any Auxiliary System at PBNP that is in close proximity to systems containing borated water is evaluated for this aging effect.
3.3.1-15	Components in or serviced by closed-cycle cooling water system	Loss of material due to general, pitting, and crevice corrosion, and MIC	Closed-cycle cooling water system	No	The Closed-Cycle Cooling Water System Surveillance Program is credited with managing these aging effects for components serviced by closed-cycle cooling water at PBNP. The One-Time Inspection Program is also used to verify the effectiveness of the closed-cycle cooling water chemistry control. Components within the Chemical and Volume Control, Component Cooling Water, Waste Disposal, Emergency Power, and Essential Ventilation Systems fall in this category.
3.3.1-16	Cranes including bridge and trolleys and rail system in load handling system	Loss of material due to general corrosion and wear	Overhead heavy load and light load handling systems	No	The Structures Monitoring Program implements the Inspection of Heavy Load and Refueling Handling Systems procedures at Point Beach. NUREG-1801 XI.M23 states that the number and magnitude of lifts made by cranes are reviewed. PBNP has not kept records of the number nor magnitude of lifts that have been made, however PBNP has addressed accumulative fatigue damage as a TLAA in Section 4.3.13. The periodic inspections are credited with managing the aging effects of loss of material due to general corrosion and wear.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-17	Components in or serviced by open-cycle cooling water systems	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-cycle cooling water system	No	The Open-Cycle Cooling (Service) Water System Surveillance Program is credited with managing these aging effects in the Auxiliary Systems at PBNP. In some cases, the Periodic Surveillance and Preventive Maintenance Program or the One-Time Inspection Program is used in lieu of the Open-Cycle Cooling Water Program, when the OCCW program is not a viable choice. Items VII.C1.3-a and VII.C1.3-b address both tube-side and shell-side environments of open-cycle to closed-cycle cooling water heat exchangers. For the component cooling water heat exchangers, in the treated water environment (shell-side of the HXs), the Closed-Cycle Cooling Water System Surveillance Program and One-Time Inspection Program are credited for managing the applicable aging effects.
3.3.1-18	Buried piping and fittings	Loss of material due to general, pitting, and crevice corrosion, and MIC	Buried piping and tanks surveillance or Buried piping and tanks inspection	No Yes, detection of aging effects and operating experience are to be further evaluated (see [SRP] subsection 3.3.2.2.11)	Further evaluation documented in Section 3.3.2.2.11.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-19	Components in compressed air system	Loss of material due to general and pitting corrosion	Compressed air monitoring	No	Components in the Plant Air System that are subject to these aging effects are managed by the Periodic Surveillance and Preventive Maintenance Program. PBNP does not have a Compressed Air Monitoring Program, however, the PSPM Program is comparable and appropriate for managing these aging effects.
3.3.1-20	Components (doors and barrier penetration seals) and concrete structures in fire protection	Loss of material due to wear; hardening and shrinkage due to weathering	Fire protection	No	The Fire Protection Program is credited with managing the aging effects of loss of material due to wear and general corrosion and hardening and shrinkage for components/structures that act as fire barriers.
3.3.1-21	Components in water-based fire protection	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling	Fire water system	No	The Fire Protection Program is credited with managing these aging effects in the Fire Protection System at PBNP.
3.3.1-22	Components in diesel fire system	Loss of material due to galvanic, general, pitting, and crevice corrosion	Fire protection and fuel oil chemistry	No	The Fuel Oil Chemistry Control Program is credited with managing these aging effects in the Fire Protection System at PBNP. The Fire Protection Program is also credited with managing these effects via performance and condition monitoring, except for the day tank.
3.3.1-23	Tanks in diesel fuel oil system	Loss of material due to general, pitting, and crevice corrosion	Above ground carbon steel tanks	No	The Systems Monitoring Program is credited with managing these aging effects for the external surfaces of above ground diesel fuel oil tanks in the Emergency Power System at PBNP. PBNP does not have an Aboveground Carbon Steel Tanks Program, however, the System Monitoring Program is comparable and appropriate for managing these aging effects.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-24	Closure bolting	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and SCC	Bolting integrity	No	The Bolting Integrity Program is credited for managing these aging effects. There are no bolts with a specified minimum yield strength > 150 ksi in the Auxiliary Systems at PBNP. Therefore, SCC is not an applicable aging effect/mechanism.
3.3.1-25	BWR only				
3.3.1-26	BWR only				
3.3.1-27	BWR only				
3.3.1-28	BWR only				
3.3.1-29	Components (aluminum bronze, brass, cast iron, cast steel) in open-cycle and closed-cycle cooling water systems, and ultimate heat sink	Loss of material due to selective leaching	Selective leaching of materials	No	At PBNP, the Open-Cycle Cooling (Service) Water System Surveillance Program, Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, and Buried Services Monitoring Program are credited for managing this aging effect for components in the Auxiliary Systems. PBNP does not have a Selective Leaching Program, however, these programs are considered adequate to manage this aging effect.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-30	Fire barriers, walls, ceilings and floors in fire protection	Concrete cracking and spalling due to freeze-thaw, aggressive chemical attack, and reaction with aggregates; loss of material due to corrosion of embedded steel	Fire protection and structures monitoring	No	The Fire Protection Program in conjunction with the Structures Monitoring Program identifies that an aging mechanism is present and active and also provides confirmation and verification of the absence of all types of aging effects. Aging effects may be absent if the materials of construction, design specifications, and operational environment preclude an aging mechanism but, it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is applicable. Concrete in indoor and outdoor environments have been evaluated for aging mechanisms. Additionally, masonry walls are used as fire barriers at Point Beach. Masonry wall inspections are incorporated into the Structures Monitoring Program. The Structures Monitoring Program effectively manages cracking due to restraint, shrinkage and creep. Operating experience has shown that concrete has not experienced unanticipated aging effects at Point Beach. That notwithstanding, the identification of aging effects by the Structures Monitoring Program, as well as the resistance provided by the materials of construction provide adequate assurance that all types of concrete aging effects will be identified and managed through out the extended period of operation.

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a, VII.E1.1-b, VII.E1.2-a, VII.E1.3-b, VII.E1.4-a, VII.E1.5-b, VII.E1.7-b, VII.E1.8-d	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
	Provide Filtration	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Flow Elements	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.E1.8-c	3.3.1-15	B
					One-Time Inspection Program	VII.E1.8-c	3.3.1-15	34
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (External)	None	None Required			8
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	VII.E1.8-b	3.3.1-09	H, 3
					Water Chemistry Control Program	VII.E1.8-b	3.3.1-09	H, 3
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.E1.8-b, VII.E1.8-c)	(3.3.1-09, 3.3.1-15)	H, 3
					One-Time Inspection Program	(VII.E1.8-b, VII.E1.8-c)	(3.3.1-09, 3.3.1-15)	H, 3

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Stainless Steel	Treated Water - Primary, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	VII.E1.8-b	3.3.1-09	H, 3
					Water Chemistry Control Program	VII.E1.8-b	3.3.1-09	H, 3
			Treated Water - Primary, 140°F<T<480°F (Internal)	Cracking due to SCC	One-Time Inspection Program	VII.E1.8-b	3.3.1-09	B, 3
					Water Chemistry Control Program	VII.E1.8-b	3.3.1-09	B, 3
				Loss Of Material	One-Time Inspection Program	VII.E1.8-b	3.3.1-09	H, 3
					Water Chemistry Control Program	VII.E1.8-b	3.3.1-09	H, 3
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
			Treated Water - Borated, T>140°F (Internal)	Cracking due to SCC	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, B, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, B, 3
				Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	35, D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	35, D

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Treated Water - Primary, 140°F<T<480°F (Internal)	Cracking due to SCC	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, B, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, B, 3
				Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Pump Casing	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.3-a, V.D1.2-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.A.3-a, V.D1.2-a)	(3.2.1-15)	35, H, 3
Tanks	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.7-b, V.D1.8-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.7-b, V.D1.8-a)	(3.2.1-15)	35, H, 3

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Thermowells	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3
			Treated Water - Primary, 140°F<T<480°F (Internal)	Cracking due to SCC	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, 34, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, B, 3
				Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3

Table 3.3.2-1 Auxiliary Systems - Chemical and Volume Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(V.C.1-b)	(3.2.1-05)	35, 4
					Water Chemistry Control Program	(V.C.1-b)	(3.2.1-05)	35, 4
			Treated Water - Primary, 140°F<T<480°F (Internal)	Cracking due to SCC	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 34, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, B, 3
				Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Flow Elements	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C2.5-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.C2.5-a)	(3.3.1-15)	F, 5

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Heat Transfer	HX-Stainless Steel[a]	N/A (External)	None	None Required			8
			Raw Water (Velocity) (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-b)	(3.3.1-17)	F, 5
			Treated Water - Other (Velocity) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(VII.C1.3-b)	(3.3.1-17)	F, E, 5
	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C1.3-a	3.3.1-17	E, 5
					One-Time Inspection Program	VII.C1.3-a	3.3.1-17	E, 5
		Stainless Steel	N/A (External)	None	None Required			8
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	F, 5
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	F, E, 5
					One-Time Inspection Program	(VII.C1.3-a)	(3.3.1-17)	F, E, 5

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Stainless Steel	Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	F, E, 5
					One-Time Inspection Program	(VII.C1.3-a)	(3.3.1-17)	F, E, 5
			Treated Water - Primary, T>480°F (Internal)	Cracking due to IGA/IGSCC	Water Chemistry Control Program	(IV.C2.2-f)	(3.1.1-36)	35, D
				Cracking due to SCC	Water Chemistry Control Program	(IV.C2.2-f)	(3.1.1-36)	35, D
				Loss Of Material	Water Chemistry Control Program	(IV.C2.2-f)	(3.1.1-36)	35, H, 5
			Treated Water - Primary, 140°F<T<480°F (Internal)	Cracking due to SCC	Water Chemistry Control Program	(IV.C2.2-f)	(3.1.1-36)	35, D
				Loss Of Material	Water Chemistry Control Program	(IV.C2.2-f)	(3.1.1-36)	35, H, 5
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program	(VIII.F.4-d)	(3.4.1-02)	35, H, 5
					Water Chemistry Control Program	(VIII.F.4-d)	(3.4.1-02)	35, H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.F.4-d)	(3.4.1-02)	35, B
					Water Chemistry Control Program	(VIII.F.4-d)	(3.4.1-02)	35, B

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrument Valve Assemblies	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program			J, 5
					One-Time Inspection Program			J, 5
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C2.2-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.C2.2-a)	(3.3.1-15)	34

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.1-a	3.3.1-15	34
Pump Casing	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.3-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.3-a	3.3.1-15	34
Radiation Monitor	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program			J, 5
					One-Time Inspection Program			J, 5

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.4-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.4-a	3.3.1-15	34
Thermowells	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.1-a	3.3.1-15	34
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C2.2-a)	(3.3.1-15)	G, 5
					One-Time Inspection Program	(VII.C2.2-a)	(3.3.1-15)	G, 5
			Containment (External)	Loss Of Material	One-Time Inspection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	One-Time Inspection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.2-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.2-a	3.3.1-15	34
		Carbon/Low Alloy Steel	Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.2-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.2-a	3.3.1-15	34
		Copper Alloy (Zn > 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-2 Auxiliary Systems- Component Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.2-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.2-a	3.3.1-15	34
			Treated Water - Other (Velocity) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.C2.2-a	3.3.1-15	B
					One-Time Inspection Program	VII.C2.2-a	3.3.1-15	34

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

Table 3.3.2-3 Auxiliary Systems- Spent Fuel Cooling System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a, VII.A3.1-a, VII.A3.2-c, VII.A3.3-c, VII.A3.4-b, VII.A3.6-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3

Table 3.3.2-3 Auxiliary Systems- Spent Fuel Cooling System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Heat Transfer	HX-Stainless Steel[a]	N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D
			Treated Water - Borated, T<140°F (Internal)	Loss of Heat Transfer due to Fouling	One-Time Inspection Program	(VII.E1.8-b)	(3.3.1-09)	H, 5
					Water Chemistry Control Program	(VII.E1.8-b)	(3.3.1-09)	H, 5
	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.3-a	3.3.1-17	B
		Stainless Steel	N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(VII.E1.8-b)	(3.3.1-09)	H, 3
					Water Chemistry Control Program	(VII.E1.8-b)	(3.3.1-09)	H, 3

Table 3.3.2-3 Auxiliary Systems- Spent Fuel Cooling System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Piping and Fittings	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Pump Casing	Pressure Boundary	Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.3-a, V.D1.2-a)	(3.2.1-15)	35, 36, H, 3
					Water Chemistry Control Program	(V.A.3-a, V.D1.2-a)	(3.2.1-15)	35, 36, H, 3

Table 3.3.2-3 Auxiliary Systems- Spent Fuel Cooling System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

Table 3.3.2-4 Auxiliary Systems- Waste Disposal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Flow Indicators[a]	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Heat Exchanger	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.C2.4-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.C2.4-a)	(3.3.1-15)	34

Table 3.3.2-4 Auxiliary Systems- Waste Disposal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Copper Alloy (Zn > 15%)	N/A (External)	None	None Required			8
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program			J, 5
					One-Time Inspection Program			J, 5
					Water Chemistry Control Program			J, 5
Instrumentation	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.F1.4-a, VII.F2.4-a, VII.F3.4-a)	(3.3.1-05)	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
		Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-4 Auxiliary Systems- Waste Disposal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Raw Water Drainage (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.D1.1-a)	(3.2.1-15)	35, H, 3
Radiation Monitor	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.1-a, V.D1.1-a)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.A.1-a, V.D1.1-a)	(3.2.1-15)	35, H, 3
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.F1.4-a, VII.F2.4-a, VII.F3.4-a)	(3.3.1-05)	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
		Cast Austenitic Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-4 Auxiliary Systems- Waste Disposal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Raw Water Drainage (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, 36, H, 3
		Stainless Steel	Indoor - No Air Conditioning (Ext)	None	None Required			J
			Treated Water - Borated, T<140°F (Internal)	Loss Of Material	One-Time Inspection Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3
					Water Chemistry Control Program	(V.A.4-a, V.D1.4-b)	(3.2.1-15)	35, H, 3

a. Selected instruments were conservatively included within the scope of License Renewal. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for License Renewal review.

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Expansion Joints	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	34, 4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D, 15
		Neoprene	Indoor - No Air Conditioning (External)	Change in Material Properties and Cracking	None Required	(VII.F1.1-c)	(3.3.1-02)	I, 16
			Raw Water (Internal)	None	None Required			J, 16
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Filters/Strainers	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	4, 34
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.6-a	3.3.1-17	B
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.6-a	3.3.1-17	B

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Pressure Boundary	Carbon/Low Alloy Steel	Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.6-a	3.3.1-17	B, 15
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.I.1-b)	(3.3.1-05)	F, 4, 34
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.6-a)	(3.3.1-17)	F, 5
	Provide Filtration	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	4, 34
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.6-a	3.3.1-17	B
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.6-a	3.3.1-17	B
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.6-a	3.3.1-17	B, 15

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Provide Filtration	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.I.1-b)	(3.3.1-05)	F, 4, 34
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.6-a)	(3.3.1-17)	F, 5
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.4-a	3.3.1-17	B
Flow Indicators[a]	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.4-a)	(3.3.1-17)	D
Heat Exchanger	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	F, 5

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heaters/Coolers	Heat Transfer	Copper Alloy (Zn < 15%)	Indoor - Wetted (External)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program	(VII.F1.2-a)	(3.3.1-05)	H, 5
			Raw Water (Velocity) (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-b)	(3.3.1-17)	H, 5
	Pressure Boundary	Copper Alloy (Zn < 15%)	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Indoor - Wetted (External)	Loss Of Material	Systems Monitoring Program	VII.F1.2-a	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.3-a	3.3.1-17	B
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.3-a	3.3.1-17	B, 15
Hose Reel	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4, 34
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrument Valve Assemblies	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D, 15
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Buried (External)	Loss Of Material	Buried Services Monitoring Program	VII.C1.1-b	3.3.1-18	A
			Containment (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	34, 4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	34, 4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.1-a	3.3.1-17	B
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.1-a	3.3.1-17	B
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.1-a	3.3.1-17	B, 15
		Stainless Steel	Containment (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.1-a	3.3.1-17	B
Pump Casing	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.5-a	3.3.1-17	B
			Raw Water (Submerged) (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.I.1-b)	(3.3.1-05)	F, 4
Radiation Monitor	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Restricting Orifices	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.4-a	3.3.1-17	B
	Restricts Flow	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.4-a	3.3.1-17	B
Sight Glass	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D
		Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D, 15

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Sight Glass	Pressure Boundary	Glass	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	None	None Required			J
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.1-a)	(3.3.1-17)	D
Thermowells	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	34, 4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	34, 4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.1-a	3.3.1-17	B
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.1-a	3.3.1-17	B, 15

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Thermowells	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.1-a	3.3.1-17	B
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	34, 4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.I.1-b	3.3.1-05	34, 4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B, 15

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.2-a)	(3.3.1-17)	F, 5, 36
					Periodic Surveillance and Preventive Maintenance Program	(VII.C1.2-a)	(3.3.1-17)	F, 5, 13
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.I.1-b)	(3.3.1-05)	F, 4, 34
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.2-a)	(3.3.1-17)	F, 5
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.2-a)	(3.3.1-17)	F, 5

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B
					Periodic Surveillance and Preventive Maintenance Program	VII.C1.2-a	3.3.1-17	13
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B, 15
					Periodic Surveillance and Preventive Maintenance Program	VII.C1.2-a	3.3.1-17	13
		Copper Alloy (Zn > 15%)	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-5 Auxiliary Systems- Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn > 15%)	Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B, 15
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.2-a	3.3.1-17	B

a. Selected instruments were conservatively included within the scope of License Renewal. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for License Renewal review.

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Accumulators/ Cylinders	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - Air Conditioning (External)	None	None Required			J
Compressor Casing	Pressure Boundary	Cast Iron	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Fire Protection Program			J, 5
			Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Expansion Joints	Pressure Boundary	Neoprene	Indoor - No Air Conditioning (External)	Change in Material Properties and Cracking	None Required	(VII.F1.1-c)	(3.3.1-02)	I, 16
			Raw Water (Stagnant) (Internal)	None	None Required			J
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
Filters/Strainers	Provide Filtration	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Fire Hydrant	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Outdoor (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
Flame Arrestors	Flame Suppression	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Fire Protection Program	(VII.G.8-a)	(3.3.1-22)	D, 19
					One-Time Inspection Program	(VII.G.7-b)	(3.3.1-06)	D

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Heat Transfer	HX-Copper Alloy (Zn < 15%)	N/A (External)	None	None required			8
			Raw Water (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Fire Protection Program			J, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Fire Protection Program			J, 5
	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	(VII.G.6-b)	(3.3.1-21)	G, 5
	Pressure Boundary	Copper Alloy (Zn < 15%)	Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	(VII.G.6-b)	(3.3.1-21)	D
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	(VII.G.6-b)	(3.3.1-21)	G, 5
			N/A (External)	None	None required			8

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Hose Reel	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
Instrument Valve Assemblies	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	(VII.G.6-b)	(3.3.1-21)	D
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Buried (External)	Loss Of Material	Buried Services Monitoring Program	VII.C1.1-b	3.3.1-18	A
			Concrete (External)	None	None Required			J

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fire Protection Program	VII.G.8-a	3.3.1-22	B
					Fuel Oil Chemistry Control Program	VII.G.8-a	3.3.1-22	B
			Outdoor (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	G, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	G, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-a	3.3.1-21	B
		Cast Iron	Buried (External)	Loss Of Material	Buried Services Monitoring Program	VII.C1.1-c, (VII.C1.1-b)	3.3.1-29, (3.3.1-18)	E, 6
			Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Outdoor (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, G, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, G, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-a	3.3.1-21	B

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Pump Casing	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
RCP Oil Collection	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	One-Time Inspection Program	VII.G.7-a, VII.G.7-b	3.3.1-06	B
		Copper Alloy (Zn > 15%)	Containment (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	One-Time Inspection Program	VII.G.7-b	3.3.1-06	B
Sight Glass	Pressure Boundary	Glass	Containment (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	None	None Required			J
Spray Nozzles	Flow Control	Copper Alloy (Zn > 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Fire Protection Program	(VII.G.6-b)	(3.3.1-21)	G, 5
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Spray Nozzles	Pressure Boundary	Copper Alloy (Zn > 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Fire Protection Program	(VII.G.6-b)	(3.3.1-21)	G, 5
			Indoor - No Air Conditioning (External)	None	None Required			J
Sprinkler Heads	Flow Control	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.G.8-a)	(3.3.1-22)	D, 40
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	(VII.G.8-a)	(3.3.1-22)	D

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fire Protection Program	VII.G.8-a	3.3.1-22	B
					Fuel Oil Chemistry Control Program	VII.G.8-a	3.3.1-22	B
			Outdoor (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	G, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	G, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
		Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil - Pooling (Internal)	Cracking due to SCC	None Required	(VII.G.8-a)	(3.3.1-22)	F, 17
				Loss Of Material	Fuel Oil Chemistry Control Program	(VII.G.8-a)	(3.3.1-22)	F, 5
					Fire Protection Program	(VII.G.8-a)	(3.3.1-22)	F, 5

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Cast Iron	Buried (External)	Loss Of Material	Buried Services Monitoring Program	VII.C1.1-c, (VII.C1.1-b)	3.3.1-29, (3.3.1-18)	E, 6
			Indoor - No Air Conditioning (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Outdoor (External)	Loss Of Material	Fire Protection Program	(VII.I.1-b)	(3.3.1-05)	F, G, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, G, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
		Copper Alloy (Zn < 15%)	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Fire Protection Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B

Table 3.3.2-6 Auxiliary Systems- Fire Protection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn > 15%)	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Fire Protection Program			J, 5
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	VII.G.6-b	3.3.1-21	B
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Fire Protection Program	(VII.G.6-b)	(3.3.1-21)	G, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Air Motor	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.2-a	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Drain Trap	Pressure Boundary	Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	None	None Required			J
Expansion Joints	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.3-a, VII.H2.4-a	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H2.5-a	3.3.1-07	B
					One-Time Inspection Program	VII.H2.5-a	3.3.1-07	B

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Expansion Joints	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34
		Elastomer	Air and Gas - Wetted, T<140°F (Internal)	Change in Mat'l Properties due to Elevated Temp.	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Elevated Temperature	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Ultraviolet Radiation and Ozone	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
			Indoor - No Air Conditioning (External	Change in Mat'l Properties due to Elevated Temp.	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Elevated Temperature	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Ultraviolet Radiation and Ozone	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Expansion Joints	Pressure Boundary	Neoprene	Air and Gas - Wetted, T<140°F (Internal)	None	None Required			J, 16
			Indoor - No Air Conditioning (External)	Change in Material Properties and Cracking	None Required			J, 16
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.4-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
Fan/blower Housing	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
			Outdoor (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Filters/Strainers	Pressure Boundary	Aluminum	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program			J, 5
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
		Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.2-a, VII.H2.3-a	3.3.1-05	4

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H2.5-a	3.3.1-07	B
					One-Time Inspection Program	VII.H2.5-a	3.3.1-07	B
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34
		Copper Alloy (Zn < 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Provide Filtration	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.2-a, VII.H2.3-a	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J. 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H2.5-a	3.3.1-07	B
					One-Time Inspection Program	VII.H2.5-a	3.3.1-07	B
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34
		Copper Alloy (Zn < 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Flame Arrestors	Flame Suppression	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Oil and Fuel Oil (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil - Pooling (Internal)	Cracking due to SCC	None Required			J, 17
				Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Flow Indicators[a]	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H2.5-a	3.3.1-07	B
					One-Time Inspection Program	VII.H2.5-a	3.3.1-07	B
Heat Exchanger	Heat Transfer	HX-Copper Alloy (Zn < 15%)[b]	Air and Gas - Wetted, T<140°F (Internal)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a)	(3.3.1-05)	F, H, 5
			N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Outdoor (External)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, H, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, H, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Heat Transfer	HX-Copper Alloy (Zn > 15%)[b]	N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, H, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, H, 5
		HX-Stainless Steel[b]	N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.H2.1-b)	(3.3.1-17)	F, H, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, H, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, H, 5
	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Carbon/Low Alloy Steel	Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.H2.1-b	3.3.1-17	B
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34
		Copper Alloy (Zn < 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a)	(3.3.1-05)	F, 5
			N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Outdoor (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	G, 5
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
		Copper Alloy (Zn > 15%)	N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Copper Alloy (Zn > 15%)	Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
		Stainless Steel	N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.H2.1-b)	(3.3.1-17)	F, 5
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
Heaters/Coolers	Heat Transfer	HX-Copper Alloy (Zn > 15%)[b]	Indoor - No Air Conditioning (External)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program	(VII.F1.2-a)	(3.3.1-05)	H, 5
			Treated Water - Other (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	H, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	H, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heaters/Coolers	Pressure Boundary	Copper Alloy (Zn > 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
Instrumentation[a]	Pressure Boundary	Glass	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	None	None Required			J
Instrument Valve Assemblies	Pressure Boundary	Copper Alloy (Zn < 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrument Valve Assemblies	Pressure Boundary	Copper Alloy (Zn < 15%)	Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
		Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a)	(3.3.1-05)	F, 5
			Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Cracking due to SCC	None Required			J, 17
				Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.2-a, VII.H2.3-a, VII.H2.4-a	3.3.1-05	4
			Buried (External)	Loss Of Material	Buried Services Monitoring Program	VII.H1.1-b	3.3.1-18	A
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H2.5-a	3.3.1-07	B
					One-Time Inspection Program	VII.H2.5-a	3.3.1-07	B
			Outdoor (External)	Loss Of Material	Systems Monitoring Program	VII.H1.1-a	3.3.1-05	4
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
		Plastic Pipe	Air and Gas - Wetted, T<140°F (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Cracking due to SCC	None Required			J, 17
				Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Pump Casing	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H2.5-a	3.3.1-07	B
					One-Time Inspection Program	VII.H2.5-a	3.3.1-07	B
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Pump Casing	Pressure Boundary	Cast Iron	Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
Restricting Orifices	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Cracking due to SCC	None Required			J, 17
				Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Restricting Orifices	Restricts Flow	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Cracking due to SCC	None Required			J, 17
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
Sight Glass	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Sight Glass	Pressure Boundary	Glass	Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	None	None Required			J
Silencer	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.3-a, VII.H2.4-a	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.2-a	3.3.1-05	4
					Tank Internal Inspection Program	VII.H2.2-a	3.3.1-05	4
			Buried (External)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H1.1-b)	(3.3.1-18)	E, 6
			Concrete (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H1.4-a	3.3.1-07	B
					One-Time Inspection Program	VII.H1.4-a	3.3.1-07	B
			Outdoor (External)	Loss Of Material	Systems Monitoring Program	VII.H1.4-b	3.3.1-23	E, 6
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34
Turbine Casing	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Turbo-Charger	Pressure Boundary	Aluminum	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.3-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program			J, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Turbo-Charger	Pressure Boundary	Cast Iron	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.3-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.H2.2-a, VII.H2.3-a, VII.H2.4-a	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	VII.H2.5-a	3.3.1-07	B
					One-Time Inspection Program	VII.H2.5-a	3.3.1-07	B
			Outdoor (External)	Loss Of Material	Systems Monitoring Program	VII.H1.2-a	3.3.1-05	4

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.H2.1-a	3.3.1-15	B
					One-Time Inspection Program	VII.H2.1-a	3.3.1-15	34
		Cast Austenitic Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a, VII.H2.3-a, VII.H2.4-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	None	None Required			J
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F. 4
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
		Copper Alloy (Zn < 15%)	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a, VII.H2.3-a, VII.H2.4-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn < 15%)	Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
		Copper Alloy (Zn > 15%)	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a, VII.H2.3-a, VII.H2.4-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5

Table 3.3.2-7 Auxiliary Systems- Emergency Power System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.H2.2-a, VII.H2.3-a, VII.H2.4-a)	(3.3.1-05)	F, 4
			Indoor - No Air Conditioning (External)	None	None Required			J
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Oil and Fuel Oil - Pooling (Internal)	Cracking due to SCC	None Required			J, 17
				Loss Of Material	Fuel Oil Chemistry Control Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
					One-Time Inspection Program	(VII.H2.5-a)	(3.3.1-07)	F, 5
			Outdoor (External)	None	None Required			J
			Treated Water - Other (Stagnant) (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.H2.1-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.H2.1-a)	(3.3.1-15)	F, 5

a. Selected instruments were conservatively included within the scope of License Renewal. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for License Renewal review.

b. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

Table 3.3.2-8 Auxiliary Systems- Containment Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Accumulators/ Cylinders	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Damper Housings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Ductwork	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Fan/blower Housing	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4

Table 3.3.2-8 Auxiliary Systems- Containment Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Filters/Strainers	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Heat Exchanger	Heat Transfer	HX-Copper Alloy (Zn < 15%)[a]	Containment (External)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program	(VII.F3.2-a)	(3.3.1-05)	H, 4
			Raw Water (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-b)	(3.3.1-17)	D
	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - Wetted (External)	Loss Of Material	Systems Monitoring Program	VII.F3.2-a	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	D

Table 3.3.2-8 Auxiliary Systems- Containment Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heaters/Coolers	Heat Transfer	HX-Copper Alloy (Zn < 15%)[b]	Containment (External)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program	(VII.F3.2-a)	(3.3.1-05)	H, 4
			Raw Water (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-b)	(3.3.1-17)	D
	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - Wetted (External)	Loss Of Material	Systems Monitoring Program	VII.F3.2-a	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	D
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Thermowells	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4

Table 3.3.2-8 Auxiliary Systems- Containment Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn > 15%)	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Elastomer	Air and Gas (Internal)	Change in Mat'l Properties due to Elevated Temp	None Required	VII.F3.1-b	3.3.1-02	I, 16
				Cracking due to Elevated Temperature	None Required	VII.F3.1-b	3.3.1-02	I, 16
				Cracking due to Ultraviolet Radiation and Ozone	None Required	(VII.F3.1-b)	(3.3.1-02)	I, 16
			Containment (External)	Change in Mat'l Properties due to Elevated Temp.	Periodic Surveillance and Preventive Maintenance Program	VII.F3.1-b	3.3.1-02	4, 18
				Cracking due to Elevated Temperature	Periodic Surveillance and Preventive Maintenance Program	VII.F3.1-b	3.3.1-02	4, 18
				Cracking due to Ultraviolet Radiation and Ozone	None Required	(VII.F3.1-b)	(3.3.1-02)	I, 16

Table 3.3.2-8 Auxiliary Systems- Containment Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Elastomer	Indoor - No Air Conditioning (External)	Change in Mat'l Properties due to Elevated Temp.	None Required	VII.F3.1-b	3.3.1-02	I, 16
				Cracking due to Elevated Temperature	None Required	VII.F3.1-b	3.3.1-02	I, 16
				Cracking due to Ultraviolet Radiation and Ozone	None Required	(VII.F3.1-b)	(3.3.1-02)	I, 16
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Damper Housings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.F1.1-a, VII.F4.1-a	3.3.1-05	4
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Ductwork	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.F1.1-a, VII.F4.1-a	3.3.1-05	4
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Ductwork	Pressure Boundary	Elastomer	Air and Gas - Wetted, T<140°F (Internal)	Change in Mat'l Properties due to Elevated Temp.	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Elevated Temperature	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Ultraviolet Radiation and Ozone	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
			Indoor - No Air Conditioning (External)	Change in Mat'l Properties due to Elevated Temp.	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Elevated Temperature	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
				Cracking due to Ultraviolet Radiation and Ozone	None Required	(VII.F1.1-b, VII.F4.1-b)	(3.3.1-02)	I, 16
Fan/blower Housing	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.F1.1-a, VII.F4.1-a	3.3.1-05	4

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Fan/blower Housing	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Filters/Strainers	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	34

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Filters/Strainers	Provide Filtration	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	34
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	F, 5

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Heat Transfer	HX-Copper Alloy (Zn < 15%)[a]	Air and Gas (Internal)	None	None Required			J
			N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.3-b	3.3.1-17	B
			Treated Water - Other (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	H, F, 5
	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.I.1-b	3.3.1-05	4
					Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.3-a	3.3.1-17	B
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	34

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Cast Iron	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.I.1-b)	(3.3.1-05)	F, 4
					Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	F, 5
		Copper Alloy (Zn < 15%)	Air and Gas (Internal)	None	None Required			J
			N/A (External)	None	None Required			8
			Raw Water (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VII.C1.3-a	3.3.1-17	B
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	F, 5

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heaters/Coolers	Heat Transfer	HX-Copper Alloy (Zn < 15%)[b]	Air and Gas - Wetted, T<140°F (Internal)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program	(VII.F1.2-a)	(3.3.1-05)	H, 5
			N/A (External)	None	None Required			8
			Treated Water - Other (Internal)	Loss of Heat Transfer due to Fouling	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	H, F, 5
		HX-Stainless Steel[b]	Air and Gas - Wetted, T<140°F (Internal)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program			J, 5
			N/A (External)	None	None Required			8
			Raw Water (Velocity) (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-b)	(3.3.1-17)	F, 5
	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.F1.2-a)	(3.3.1-05)	F, 5
			Indoor - Air Conditioning (External)	None	None Required			J
		Copper Alloy (Zn < 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.F1.2-a	3.3.1-05	4
			N/A (External)	None	None Required			8

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heaters/Coolers	Pressure Boundary	Copper Alloy (Zn < 15%)	Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
		Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.F1.2-a)	(3.3.1-05)	F, 5
			N/A (External)	None	None Required			8
			Raw Water (Velocity) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	(VII.C1.3-a)	(3.3.1-17)	F, 5
Humidifier	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.F1.1-a	3.3.1-05	4
			Indoor - Air Conditioning (External)	None	None Required			J

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrument Valve Assemblies	Pressure Boundary	Copper Alloy (Zn < 15%)	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J
		Stainless Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5
			Indoor - No Air Conditioning (External)	None	None Required			J
Instrumentation[b]	Pressure Boundary	Glass	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	None	None Required			J
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	VII.F1.3-a	3.3.1-15	B
					One-Time Inspection Program	VII.F1.3-a	3.3.1-15	34

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J
Pump Casing	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	34
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	34
Thermowells	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Thermowells	Pressure Boundary	Stainless Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	D
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	34
		Copper Alloy (Zn < 15%)	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	F, 5

Table 3.3.2-9 Auxiliary Systems- Essential Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Indoor - Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	Closed-Cycle Cooling Water System Surveillance Program	(VII.F1.3-a)	(3.3.1-15)	F, 5
					One-Time Inspection Program	(VII.F1.3-a)	(3.3.1-15)	F, 5

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

b. Selected instruments were conservatively included within the scope of License Renewal. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for License Renewal review.

Table 3.3.2-10 Auxiliary Systems- Plant Sampling System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Plant Sampling System components are addressed in Table 3.1.2-1, Table 3.2.2-3, Table 3.3.2-1, and Table 3.3.2-2.								

Table 3.3.2-11 Auxiliary Systems - Plant Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Accumulators/ Cylinders	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Compressor Casing	Pressure Boundary	Cast Iron	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2

Table 3.3.2-11 Auxiliary Systems - Plant Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Fasteners/ Bolting	Mechanical Closure Integrity	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Filters/Strainers	Pressure Boundary	Plastic Pipe	Air and Gas - Wetted, T<140°F (Internal)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J
	Provide Filtration	Plastic Pipe	Air and Gas - Wetted, T<140°F (Internal)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J
Flow Indicators[a]	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-11 Auxiliary Systems - Plant Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.D.1-a	3.3.1-19	E, 6
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
		Copper Alloy (Zn < 15%)	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.D.1-a)	(3.3.1-19)	F, E, 6
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-11 Auxiliary Systems - Plant Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.D.3-a	3.3.1-19	E, 6
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VII.D.2-a	3.3.1-19	E, 6
			Containment (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
		Copper Alloy (Zn < 15%)	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.D.2-a)	(3.3.1-19)	F, E, 6
			Containment (External)	None	None Required			J

Table 3.3.2-11 Auxiliary Systems - Plant Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Copper Alloy (Zn > 15%)	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.D.2-a)	(3.3.1-19)	F, E, 6
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.D.2-a)	(3.3.1-19)	F, E, 6

Table 3.3.2-11 Auxiliary Systems - Plant Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - Air Conditioning (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

a. Selected instruments were conservatively included within the scope of License Renewal. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for License Renewal review.

Table 3.3.2-12 Auxiliary Systems - Containment Hydrogen Detector and Recombiner System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4

Table 3.3.2-12 Auxiliary Systems - Containment Hydrogen Detector and Recombiner System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
		Cast Austenitic Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.3.2-13 Auxiliary Systems - Circulating Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Expansion Joints	Pressure Boundary	Neoprene	Indoor - No Air Conditioning (External)	Change in Material Properties and Cracking	None Required	(VII.F1.1-c)	(3.3.1-02)	I, 16
			Raw Water (Internal)	None	None Required			J, 16
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.C1.1-a)	(3.3.1-17)	E, 6
		Plastic Pipe	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water (Internal)	None	None Required			J

Table 3.3.2-13 Auxiliary Systems - Circulating Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Pump Casing	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.C1.5-a)	(3.3.1-17)	E, 6
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.C1.2-a)	(3.3.1-17)	E, 6
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Raw Water (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VII.C1.2-a)	(3.3.1-17)	E, 6

Table 3.3.2-14 Auxiliary Systems - Treated Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water Drainage (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
			Treated Water - Other (Internal)	Loss Of Material	One-Time Inspection Program			J, 41
		Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	One-Time Inspection Program			J, 41

Table 3.3.2-14 Auxiliary Systems - Treated Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Raw Water Drainage (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
			Treated Water - Other (Internal)	Loss Of Material	One-Time Inspection Program			J, 41
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Raw Water Drainage (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
		Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	One-Time Inspection Program			J, 41
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Other (Internal)	Loss Of Material	One-Time Inspection Program			J, 41

Table 3.3.2-15 Auxiliary Systems - Heating Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VII.I.1-a	3.3.1-14	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VII.I.2-a	3.3.1-24	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Filters/Strainers	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.C.1-b)	(3.4.1-02)	F, 5, 35
					Water Chemistry Control Program	(VIII.C.1-b)	(3.4.1-02)	F, 5, 35
Heaters/Coolers	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
					Water Chemistry Control Program			J, 5

Table 3.3.2-15 Auxiliary Systems - Heating Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.C.1-b, VIII.E.1-b	3.4.1-02	B, 35
					Water Chemistry Control Program	VIII.C.1-b, VIII.E.1-b	3.4.1-02	B, 35
				Loss of Material due to FAC/Erosion-Corrosion	None Required	VIII.C.1-a, VIII.E.1-a	3.4.1-06	I, 12, 35
Pump Casing	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.E.3-a)	(3.4.1-02)	F, 5, 35
					Water Chemistry Control Program	(VIII.E.3-a)	(3.4.1-02)	F, 5, 35
Steam Traps	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.C.1-b	3.4.1-02	B, 35
					Water Chemistry Control Program	VIII.C.1-b	3.4.1-02	B, 35

Table 3.3.2-15 Auxiliary Systems - Heating Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Steam Traps	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Loss of Material due to FAC/Erosion-Corrosion	None Required	VIII.C.1-a	3.4.1-06	I, 12, 35
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.C.1-b)	(3.4.1-02)	F, 5, 35
					Water Chemistry Control Program	(VIII.C.1-b)	(3.4.1-02)	F, 5, 35
Tanks	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.E.5-a)	(3.4.1-02)	F, 5, 35
					Water Chemistry Control Program	(VIII.E.5-a)	(3.4.1-02)	F, 5, 35
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	H, 5, 35
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	H, 5, 35

Table 3.3.2-15 Auxiliary Systems - Heating Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Stainless Steel	Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	D, 35
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	D, 35
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VII.I.1-b	3.3.1-05	4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.C.2-b, VIII.E.2-b	3.4.1-02	B, 35
					Water Chemistry Control Program	VIII.C.2-b, VIII.E.2-b	3.4.1-02	B, 35
				Loss of Material due to FAC/Erosion-Corrosion	None Required	VIII.C.2-a, VIII.E.2-a	3.4.1-06	I, 12, 35
		Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VII.I.1-b)	(3.3.1-05)	F, 4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.E.2-b)	(3.4.1-02)	F, 5, 35
					Water Chemistry Control Program	(VIII.E.2-b)	(3.4.1-02)	F, 5, 35

Table 3.3.2-15 Auxiliary Systems - Heating Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program			J, 5
					Water Chemistry Control Program			J, 5

Table 3.3.2-16 Auxiliary Systems - Fuel Handling System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Fuel Handling System components are addressed in Table 3.3.2-3, Table 3.5.2-1, and Table 3.5.2-6.								

Notes for Tables 3.3.2-1 through 3.3.2-16

A Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP has exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP has exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect but a different AMP is credited.

F Material not in NUREG-1801 for this component.

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

I Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-specific notes:

1 The CS Component asset was created to manage Boric Acid wastage of external surfaces only (for any carbon steel, low alloy steel, or cast iron component, including bolting), and therefore internal environments for this asset are not applicable. All other internal and external aging effects are identified separately under the specific component type.

2 Internal aging effects are not applicable. Due to the way data is entered into the LRDB, the internal environment of some components is listed as N/A (e.g. bolting, walls, clad vessels, structural steel, etc.).

3 Although the NUREG references a temperature gate of < 90 degrees C (200 degrees F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140 degrees F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The aging effect identified by PBNP (loss of material) for temperatures < 140 degrees F differs from that of the NUREG. That not withstanding, the Water Chemistry Control Program, which is credited

for managing the aging effects for all temperatures, will preclude the possibility of crack initiation and growth due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of the Chemistry program.

4 Plant specific program identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

5 Material/environment combination and/or aging effect not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

6 Program different than identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

7 There are no bolts with a specified minimum yield strength > 150 ksi in this system. Therefore, SCC is not an applicable aging effect/mechanism.

8 External aging effects are not applicable. Due to the way data is entered into the LRDB, the external environment of some components is listed as N/A (e.g. cladding, HX tubing, or other components that are entirely contained within another component).

9 AFW pump bearing coolers are integral to the bearing housing.

10 FE housing is CS but venturi is SS.

11 Internal portions of AFW turbine exhaust that are open to atmosphere.

12 Some components in this system experience a temperature below 200 degrees F, insufficient flow to support FAC, or operate less than 2% of the time. The components that fall in this category do not require aging management for FAC.

13 Some components are replaced on a specified frequency that precludes aging effects from resulting in loss of intended function. Periodic Surveillance and Preventive Maintenance Program is used to replace these components.

14 AFW Pump turbine casing's environment is more closely related to Main Steam environments, since it is not addressed in Chapter VIII.G Aux Feedwater System.

15 Components in this grouping do not have flow velocities >10 fps, and therefore loss of material due to erosion is not an aging effect requiring management.

16 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not

subject to temperatures where change in material properties or cracking could occur (>95 degrees F). Therefore no aging management is required.

17 SCC is not a concern for this material/environment group, due to temperatures being <140 degrees F.

18 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are subject to temperatures where change in material properties or cracking could occur (>95 degrees F).

19 Fuel Oil Chemistry Control Program is not necessary for managing the aging effects for a flame arrestor.

20 ISI inspections are not performed on this component, and therefore the ISI Program is not credited for managing the aging of this component.

21 Materials science supports loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The Water Chemistry Control Program is credited for managing the aging effects for all temperatures.

22 NUREG-1801 has loss of fracture toughness as an aging effect for this component. However, fluence levels for this component are below the threshold value, and therefore effects are not significant and do not require aging management.

23 NUREG-1801 credits the ISI Program for managing loss of material. PBNP does credit the ISI Program for managing cracking on this same component, and these inspections will identify loss of material/pitting, but only in the area of interest (at the weld). The Steam Generator Integrity Program is being included as it performs more general area inspections of the secondary side of the SGs. Previous visual inspections have confirmed no indications of loss of material.

24 This NUREG-1801 line item lists Loss of Material/Corrosion for the Aging Effect/Mechanism. This is interpreted to include the mechanisms of general and boric acid corrosion.

25 Tendon, loss of prestress NUREG-1801, line item 3.5.1-11/II.A1.3-b, is not addressed in this table. Refer to Section 4.0 on TLAAs.

26 No aging effects requiring management were identified for concrete (buried, indoor, or outdoor) and grout (except for Component Supports), however, concrete and grout is periodically monitored for potential degradation by an applicable license renewal program. See Appendix B for a discussion of the aging management programs used for concrete and grout.

27 Support (component or pipe) baseplates and their attachment to the structure (typically with embedded bolts or expansion anchors) are not within the scope of IWF and are considered

a part of the structure. However, for completeness, these items, including grout, are inspected when performing an IWF inspection. It is for this reason, that an ASME component support inspection will also be assigned against the Structures Monitoring Program.

28 The NUREG-1801 Volume I, line item 3.3.1-20, does not include the Control Building (Group 1 Structure), therefore, a comparable Group 3 Structure was chosen.

29 Doors that are assigned to the Structures Monitoring Program include those with the HELB function. Doors that are assigned to the Fire Protection Program include those with the fire or flood function. Note that some doors are common to both programs.

30 The Fire Barrier intended function is assigned to containment piping and electrical penetrations, fuel transfer tube, liner, and airlocks component types.

31 The fuel transfer tube is included with this component type (containment pressure boundary), therefore, the aging management program is appropriate.

32 Containment penetration sleeves, cracking/cyclic loading NUREG-1801, line item 3.5.1-2/II.A3.1-c, is not addressed in this table. Refer to Section 4.0 on TLAAs.

33 Crane, fatigue damage NUREG-1801, line item 3.3.1-3/VII.B.1-a, is not addressed in this table. Refer to Section 4.0 on TLAAs.

34 Consistent with NUREG-1801 for material, environment, aging effect and an additional AMP is credited.

35 Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter.

36 The material identified in this NUREG-1801 line item is stainless steel. The aging effects of stainless steel are the same as those for Cast Austenitic Stainless Steel at temperatures < 482 degrees F.

37 Unit 1 inspection port bolting has been identified by Westinghouse as being fatigue sensitive and needing replacement every 12 years. The Periodic Surveillance and Preventive Maintenance Program will be used to replace this bolting on a 10 year frequency.

38 The Unit 2 Steam Generators were designed and fabricated to eliminate the need for certain Section XI weld examinations. The Unit 2 transition cones are fabricated such that the girth welds are not at the discontinuity, and therefore Section XI does not require these welds to be periodically inspected. The steam nozzles were also fabricated integral to the elliptical head, and therefore there is no steam nozzle weld to inspect.

39 The One-Time Inspection is only for the letdown orifices, which is in response to NRC IN 98-045, "Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds."

40 The Fuel Oil Chemistry Control Program includes provisions for performing tests/inspections for detecting tank wall loss.

41 In some cases where the Water Chemistry Control Program is not a viable option and aging effects are not expected to be significant, the One-Time Inspection Program alone is credited for managing aging effects. The One-Time Inspection Program has provisions to increase frequency of inspections based on the results of the first inspection.

3.4 Aging Management of Steam and Power Conversion System

3.4.1 Introduction

This section provides the results of the aging management review for those components identified in Section 2.3.4, Steam and Power Conversion Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section, are described in the indicated sections.

- Main and Auxiliary Steam System (Section 2.3.4.1)
- Feedwater and Condensate System (Section 2.3.4.2)
- Auxiliary Feedwater System (Section 2.3.4.3)

Table 3.4.1, Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Steam and Power Conversion Systems, provides the summary of the programs evaluated in NUREG-1801 for the Steam and Power Conversion Systems component groups that are relied on for license renewal.

This table uses the format described in Section 3.0 above. Note that this table only includes those component groups that are applicable to a PWR.

3.4.2 Results

The following tables summarize the results of the aging management review for systems in the Steam and Power Conversion Systems group:

Table 3.4.2-1, Steam and Power Conversion Systems - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Table 3.4.2-2, Steam and Power Conversion Systems - Feedwater and Condensate System - Summary of Aging Management Evaluation

Table 3.4.2-3, Steam and Power Conversion Systems - Auxiliary Feedwater System - Summary of Aging Management Evaluation

The materials that specific components are fabricated from, the environments to which components are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above systems in the following subsections of Section 3.4.2.1, Materials, Environment, Aging Effects Requiring Management and Aging Management Programs:

Section 3.4.2.1.1, Main and Auxiliary Steam System

Section 3.4.2.1.2, Feedwater and Condensate System

Section 3.4.2.1.3, Auxiliary Feedwater System

3.4.2.1 Materials, Environment, Aging Effects Requiring Management and Aging Management Programs

3.4.2.1.1 Main and Auxiliary Steam System

Materials

The materials of construction for the Main and Auxiliary Steam System components are:

- Carbon/Low Alloy Steel
- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Stainless Steel

Environment

The Main and Auxiliary Steam System components are exposed to the following environments:

- Air and Gas (Internal)
- Air and Gas - Wetted, T<140°F (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)
- Treated Water - Secondary, T<120°F (Internal)
- Treated Water - Secondary, T>120°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Main and Auxiliary Steam System, require management:

- Cracking due to SCC
- Loss Of Material
- Loss of Material due to FAC/Erosion-Corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the Main and Auxiliary Steam System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.4.2.1.2 Feedwater and Condensate System

Materials

The materials of construction for the Feedwater and Condensate System components are:

- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Stainless Steel

Environment

The Feedwater and Condensate System components are exposed to the following environments:

- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Treated Water - Secondary, T<120°F (Internal)
- Treated Water - Secondary, T>120°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Feedwater and Condensate System, require management:

- Cracking due to SCC
- Loss Of Material

- Loss of Material due to FAC/Erosion-Corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the Feedwater and Condensate System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Control Program

3.4.2.1.3 Auxiliary Feedwater System

Materials

The materials of construction for the Auxiliary Feedwater System components are:

- Aluminum
- Carbon/Low Alloy Steel
- Cast Austenitic Stainless Steel
- Cast Iron
- Copper Alloy (Zn < 15%)
- Copper Alloy (Zn > 15%)
- Stainless Steel

Environment

The Auxiliary Feedwater System components are exposed to the following environments:

- Air and Gas (Internal)
- Borated Water Leaks (External)
- Containment (External)
- Indoor - No Air Conditioning (External)
- Oil and Fuel Oil (Internal)
- Raw Water (Stagnant) (Internal)

- Treated Water - Secondary, T<120°F (Internal)
- Treated Water - Secondary, T>120°F (Internal)

Aging Effects Requiring Management

The following aging effects, associated with the Auxiliary Feedwater System, require management:

- Loss of Heat Transfer due to Fouling
- Loss Of Material
- Loss of Material due to FAC/Erosion-Corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the Auxiliary Feedwater System components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Open-Cycle Cooling (Service) Water System Surveillance Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Tank Internal Inspection Program
- Water Chemistry Control Program

3.4.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

NUREG-1801 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Steam and Power Conversion Systems, those programs are addressed in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

Fatigue is a 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 separately in Section 4.3.

3.4.2.2.2 Loss of Material due to General, Pitting, and Crevice Corrosion

For Steam and Power Conversion components, the Water Chemistry Control Program and One-Time Inspection Program are credited for managing these aging effects/mechanisms. In addition to these programs, the Periodic Surveillance and Preventive Maintenance Program or Tank Internal Inspection Program is also credited for managing a few selected components.

3.4.2.2.3 Loss of Material due to General, Pitting, and Crevice Corrosion, Microbiologically Influenced Corrosion, and Biofouling

The components identified in this line item relate to the untreated water from the backup water supply in a PWR auxiliary feedwater system. For PBNP, these components are evaluated in the Service Water System, which are addressed in NUREG-1801, Chapter VII (Auxiliary Systems), Section C1.

3.4.2.2.4 General Corrosion

The plant specific program credited for managing this aging effect is the Systems Monitoring Program.

3.4.2.2.5.1 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

This line item relates to the oil-side of bearing oil coolers in a PWR auxiliary feedwater system. The plant specific program credited for managing these aging effects/mechanisms at PBNP is the Periodic Surveillance and Preventive Maintenance Program.

3.4.2.2.5.2 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

This line item relates to buried components in a PWR auxiliary feedwater system. PBNP does not have buried components in the Steam and Power Conversion Systems, and therefore this line item is not applicable.

3.4.2.3 Time-Limited Aging Analysis

The time-limited aging analyses (TLAA) identified below are associated with the Steam and Power Conversion Systems components. The section of the LRA that contains the TLAA review results is indicated in parenthesis.

- Fatigue (Section 4.3, Metal Fatigue)

3.4.3 Conclusion

The Steam and Power Conversion Systems piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Steam and Power Conversion Systems components are identified in the summaries in Section 3.4.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the Steam and Power Conversion Systems components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.4.1 Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-01	Piping and fittings in main feedwater line, steam line and AFW piping (PWR only)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA (see [SRP] subsection 3.4.2.2.1)	Further evaluation documented in Section 3.4.2.2.1.
3.4.1-02	Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head and shell (except main steam system)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Water chemistry and one-time inspection	Yes, detection of aging effects is to be further evaluated (see [SRP] subsection 3.4.2.2.2)	Further evaluation documented in Section 3.4.2.2.2.
3.4.1-03	Auxiliary feedwater (AFW) piping	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Plant specific	Yes, plant specific (see [SRP] subsection 3.4.2.2.3)	This line item was not used for PBNP. Further evaluation documented in Section 3.4.2.2.3.
3.4.1-04	Oil coolers in AFW system (lubricating oil side possibly contaminated with water)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC	Plant specific	Yes, plant specific (see [SRP] subsection 3.4.2.2.5.1)	Further evaluation documented in Section 3.4.2.2.5.1.
3.4.1-05	External surface of carbon steel components	Loss of material due to general corrosion	Plant specific	Yes, plant specific (see [SRP] subsection 3.4.2.2.4)	Further evaluation documented in Section 3.4.2.2.4.

Table 3.4.1 Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-06	Carbon steel piping and valve bodies	Wall thinning due to flow-accelerated corrosion	Flow-accelerated corrosion	No	The Flow-Accelerated Corrosion Program is augmented by the Water Chemistry Control Program for management of this aging effect at PBNP. Some components in the S&PC systems experience a temperature below 200°F, insufficient flow to support FAC, or operate less than 2% of the time. The components that fall in this category do not require aging management for FAC.
3.4.1-07	Carbon steel piping and valve bodies in main steam system	Loss of material due to pitting and crevice corrosion	Water chemistry	No	The Water Chemistry Control Program is augmented by the One-Time Inspection Program at PBNP, for verifying the effectiveness of water chemistry control in S&PC systems. In addition to these programs, the Periodic Surveillance and Preventive Maintenance Program is credited for managing this aging effect for a few selected components that are periodically replaced.
3.4.1-08	Closure bolting in high-pressure or high-temperature systems	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity	No	There are no bolts with a specified minimum yield strength > 150 ksi in the Steam and Power Conversion Systems at PBNP. Therefore, SCC is not an applicable aging effect/mechanism. The Bolting Integrity Program is used to manage loss of material of bolting in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-09	Heat exchangers and coolers/ condensers serviced by open-cycle cooling water	Loss of material due to general (carbon steel only), pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-cycle cooling water system	No	Callups (PMs) under the PBNP Open-Cycle Cooling (Service) Water System Surveillance Program are used to manage these aging effects in the S&PC systems. For a few selected components in the S&PC systems, the One-Time Inspection Program is used in lieu of the OCCW Program. In these cases, plant-specific OE did not warrant periodic inspections. However, additional inspections may be performed based on the results of these evaluations.
3.4.1-10	Heat exchangers and coolers/ condensers serviced by closed-cycle cooling water	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Closed-cycle cooling water system	No	There are no heat exchangers in the Steam and Power Conversion Systems that are serviced by closed-cycle cooling water at PBNP, and therefore this line item is not applicable.
3.4.1-11	External surface of above ground condensate storage tank	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Above ground carbon steel tanks	No	This line item was not used. The external surfaces of the above ground condensate storage tanks at PBNP are addressed in Item Number 3.4.1-05.
3.4.1-12	External surface of buried condensate storage tank and AFW piping	Loss of material due to general, pitting, and crevice corrosion and MIC	Buried piping and tanks surveillance or Buried piping and tanks inspection	No Yes, detection of aging effects and operating experience are to be further evaluated (see [SRP] subsection 3.4.2.2.5.2)	Further evaluation documented in Section 3.4.2.2.5.2.

Table 3.4.1 Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-13	External surface of carbon steel components	Loss of material due to boric acid corrosion	Boric acid corrosion	No	Consistent with NUREG-1801. The Boric Acid Corrosion Program is credited with managing this aging effect in the S&PC systems at PBNP.

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VIII.H.1-a	3.4.1-13	A
			N/A (Internal)	None	None Required			1
Drain Trap	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.C.1-b	3.4.1-02	B
					Water Chemistry Control Program	VIII.C.1-b	3.4.1-02	B
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VIII.H.2-a	3.4.1-08	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VIII.H.2-a	3.4.1-08	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Flow Elements	Flow Control	Stainless Steel	N/A (External)	None	None Required			8
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
					Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	D
	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4, 10
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.B1.1-a	3.4.1-07	34, 10
					Water Chemistry Control Program	VIII.B1.1-a	3.4.1-07	B, 10
				Loss of Material due to FAC/Erosion-Corrosion	Flow-Accelerated Corrosion Program	VIII.B1.1-c	3.4.1-06	A, 10
					Water Chemistry Control Program	VIII.B1.1-c	3.4.1-06	34, 10

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Flow Elements	Pressure Boundary	Stainless Steel	N/A (External)	None	None Required			8
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
					Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	D
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
					Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	D

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.H.1-b)	(3.4.1-05)	4, 11
			Containment (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Outdoor (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.B1.1-a, VIII.C.1-b, VIII.F.1-b	3.4.1-02, 3.4.1-07	B
					Water Chemistry Control Program	VIII.B1.1-a, VIII.C.1-b, VIII.F.1-b	3.4.1-02, 3.4.1-07	B
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.B1.1-a, VIII.C.1-b, VIII.F.1-b	3.4.1-02, 3.4.1-07	B
					Water Chemistry Control Program	VIII.B1.1-a, VIII.C.1-b, VIII.F.1-b	3.4.1-02, 3.4.1-07	B

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Loss of Material due to FAC/Erosion-Corrosion	Water Chemistry Control Program	VIII.B1.1-c, VIII.C.1-a, VIII.F.1-a	3.4.1-06	34
					Flow-Accelerated Corrosion Program	VIII.B1.1-c, VIII.C.1-a, VIII.F.1-a	3.4.1-06	A
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
					Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Restricting Orifices	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
					Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D
Steam Traps	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.C.1-b	3.4.1-02	D
					Water Chemistry Control Program	VIII.C.1-b	3.4.1-02	D
				Loss of Material due to FAC/ Erosion-Corrosion	Flow-Accelerated Corrosion Program	VIII.B1.1-c, VIII.C.1-a	3.4.1-06	A
					Water Chemistry Control Program	VIII.B1.1-c, VIII.C.1-a	3.4.1-06	34

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas - Wetted, T<140°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.H.1-b)	(3.4.1-05)	4, 11
			Containment (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	One-Time Inspection Program	VIII.H.1-b	3.4.1-05	34
					Periodic Surveillance and Preventive Maintenance Program	VIII.H.1-b	3.4.1-05	34, 13
					Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.B1.2-a, VIII.C.2-b, VIII.F.2-b	3.4.1-02, 3.4.1-07	B
					Water Chemistry Control Program	VIII.B1.2-a, VIII.C.2-b, VIII.F.2-b	3.4.1-02, 3.4.1-07	B

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.B1.2-a, VIII.C.2-b, VIII.F.2-b	3.4.1-02, 3.4.1-07	B
					Periodic Surveillance and Preventive Maintenance Program	VIII.B1.2-a, VIII.C.2-b, VIII.F.2-b	3.4.1-02, 3.4.1-07	34, 13
					Water Chemistry Control Program	VIII.B1.2-a, VIII.C.2-b, VIII.F.2-b	3.4.1-02, 3.4.1-07	B
				Loss of Material due to FAC/Erosion-Corrosion	Flow-Accelerated Corrosion Program	VIII.B1.2-b, VIII.C.2-a, VIII.F.2-a	3.4.1-06	A
					None Required	VIII.B1.2-b, VIII.C.2-a, VIII.F.2-a	3.4.1-06	I, 12
					Water Chemistry Control Program	VIII.B1.2-b, VIII.C.2-a, VIII.F.2-a	3.4.1-06	34
		Copper Alloy (Zn < 15%)	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.4.2-1 Steam and Power Conversion System - Main and Auxiliary Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn > 15%)	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
					Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D

Table 3.4.2-2 Steam and Power Conversion System - Feedwater and Condensate System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VIII.H.1-a	3.4.1-13	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VIII.H.2-a	3.4.1-08	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VIII.H.2-a	3.4.1-08	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2
Flow Elements	Flow Control	Stainless Steel	N/A (External)	None	None Required			8
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
				Cracking due to SCC	Water Chemistry Control Program			H, 5

Table 3.4.2-2 Steam and Power Conversion System - Feedwater and Condensate System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Flow Elements	Flow Control	Stainless Steel	Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	D
	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4, 10
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.D1.1-c	3.4.1-02	B, 10
					Water Chemistry Control Program	VIII.D1.1-c	3.4.1-02	B, 10
				Loss of Material due to FAC/Erosion-Corrosion	Flow-Accelerated Corrosion Program	VIII.D1.1-a	3.4.1-06	A, 10
					Water Chemistry Control Program	VIII.D1.1-a	3.4.1-06	34, 10
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5

Table 3.4.2-2 Steam and Power Conversion System - Feedwater and Condensate System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	D
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.D1.1-c	3.4.1-02	B
					Water Chemistry Control Program	VIII.D1.1-c	3.4.1-02	B
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.D1.1-c	3.4.1-02	B
					Water Chemistry Control Program	VIII.D1.1-c	3.4.1-02	B

Table 3.4.2-2 Steam and Power Conversion System - Feedwater and Condensate System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Loss of Material due to FAC/Erosion-Corrosion	Flow-Accelerated Corrosion Program	VIII.D1.1-a	3.4.1-06	A
					None Required	VIII.D1.1-a	3.4.1-06	I, 12
					Water Chemistry Control Program	VIII.D1.1-a	3.4.1-06	34
		Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	One-Time Inspection Program	VIII.H.1-b	3.4.1-05	34
					Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.D1.2-b	3.4.1-02	B
					Water Chemistry Control Program	VIII.D1.2-b	3.4.1-02	B

Table 3.4.2-2 Steam and Power Conversion System - Feedwater and Condensate System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.D1.2-b	3.4.1-02	B
					Water Chemistry Control Program	VIII.D1.2-b	3.4.1-02	B
				Loss of Material due to FAC/Erosion-Corrosion	Flow-Accelerated Corrosion Program	VIII.D1.2-a	3.4.1-06	A
					None Required	VIII.D1.2-a	3.4.1-06	I, 12
					Water Chemistry Control Program	VIII.D1.2-a	3.4.1-06	34
		Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D, 36
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D, 36

Table 3.4.2-2 Steam and Power Conversion System - Feedwater and Condensate System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D
			Treated Water - Secondary, T>120°F (Internal)	Cracking due to SCC	One-Time Inspection Program			H, 5
					Water Chemistry Control Program			H, 5
				Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Accumulators/ Cylinders	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
CS Components	Pressure Boundary	Carbon/Low Alloy Steel	Borated Water Leaks (External)	Loss Of Material	Boric Acid Corrosion Program	VIII.H.1-a	3.4.1-13	A
			N/A (Internal)	None	None Required			1
Fasteners/ Bolting	Mechanical Closure Integrity	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Bolting Integrity Program	VIII.H.2-a	3.4.1-08	B, 7
			Indoor - No Air Conditioning (External)	Loss Of Material	Bolting Integrity Program	VIII.H.2-a	3.4.1-08	B, 7
			N/A (Internal)	None	None Required			2
		Stainless Steel	Containment (External)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			N/A (Internal)	None	None Required			2

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Flow Elements	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D
Heat Exchanger	Heat Transfer	HX-Stainless Steel[a]	N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss of Heat Transfer due to Fouling	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	H, 5
			Raw Water (Stagnant) (Internal)	Loss of Heat Transfer due to Fouling	Open-Cycle Cooling (Service) Water System Surveillance Program	VIII.G.5-b	3.4.1-09	B
	Pressure Boundary	Cast Iron	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	(VIII.H.1-b)	(3.4.1-05)	F, 5
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	(VIII.G.5-d)	(3.4.1-04)	F, 4
			Raw Water (Stagnant) (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.5-a)	(3.4.1-09)	F, 9

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Heat Exchanger	Pressure Boundary	Stainless Steel	N/A (External)	None	None Required			8
			Oil and Fuel Oil (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program	VIII.G.5-d	3.4.1-04	4
			Raw Water (Stagnant) (Internal)	Loss Of Material	Open-Cycle Cooling (Service) Water System Surveillance Program	VIII.G.5-a	3.4.1-09	B
Instrument Valve Assemblies	Pressure Boundary	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.E.5-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.E.5-b)	(3.4.1-02)	D
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.G.1-c	3.4.1-02	B
					Water Chemistry Control Program	VIII.G.1-c	3.4.1-02	B

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Piping and Fittings	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.G.1-c	3.4.1-02	B
					Water Chemistry Control Program	VIII.G.1-c	3.4.1-02	B
				Loss of Material due to FAC/Erosion-Corrosion	Flow-Accelerated Corrosion Program	VIII.G.1-a	3.4.1-06	A
					Water Chemistry Control Program	VIII.G.1-a	3.4.1-06	34
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.G.4-b	3.4.1-02	D
					Water Chemistry Control Program	VIII.G.4-b	3.4.1-02	D
Pump Casing	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.G.2-a	3.4.1-02	B
					Water Chemistry Control Program	VIII.G.2-a	3.4.1-02	B

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Restricting Orifices	Pressure Boundary	Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	F, 36, 5
				Loss Of Material	Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	F, 36, 5
	Restricts Flow	Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	F, 36, 5
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	F, 36, 5
Tanks	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.G.4-a	3.4.1-02	B
					Tank Internal Inspection Program	VIII.G.4-a	3.4.1-02	34
					Water Chemistry Control Program	VIII.G.4-a	3.4.1-02	B

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
Turbine Casing	Pressure Boundary	Carbon/Low Alloy Steel	Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.B1.1-a, VIII.C.1-b)	(3.4.1-02, 3.4.1-07)	D, 14
					Water Chemistry Control Program	(VIII.B1.1-a, VIII.C.1-b)	(3.4.1-02, 3.4.1-07)	D, 14
Valve Bodies	Pressure Boundary	Aluminum	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program			F, 5
		Carbon/Low Alloy Steel	Containment (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Carbon/Low Alloy Steel	Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.G.3-a	3.4.1-02	B
					Water Chemistry Control Program	VIII.G.3-a	3.4.1-02	B
			Treated Water - Secondary, T>120°F (Internal)	Loss Of Material	One-Time Inspection Program	VIII.G.3-a	3.4.1-02	B
					Water Chemistry Control Program	VIII.G.3-a	3.4.1-02	B
				Loss of Material due to FAC/Erosion-Corrosion	Flow-Accelerated Corrosion Program	(VIII.G.1-a)	(3.4.1-06)	C
					Water Chemistry Control Program	(VIII.G.1-a)	(3.4.1-06)	34
		Cast Austenitic Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	F, 5, 36
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	F, 5, 36
		Copper Alloy (Zn < 15%)	Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	Periodic Surveillance and Preventive Maintenance Program			J, 5, 13

Table 3.4.2-3 Steam and Power Conversion System - Auxiliary Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Copper Alloy (Zn > 15%)	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
		Stainless Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	None	None Required			J
			Treated Water - Secondary, T<120°F (Internal)	Loss Of Material	One-Time Inspection Program	(VIII.G.4-b)	(3.4.1-02)	D
					Water Chemistry Control Program	(VIII.G.4-b)	(3.4.1-02)	D
Valve Operator	Pressure Boundary	Carbon/Low Alloy Steel	Air and Gas (Internal)	None	None Required			J
			Indoor - No Air Conditioning (External)	Loss Of Material	Systems Monitoring Program	VIII.H.1-b	3.4.1-05	4

a. Material prefixes with HX are used to identify heat exchanger materials which perform a heat transfer intended function in addition to the typical material usage function of pressure boundary.

Notes for Tables 3.4.2-1 through 3.4.2-3

A Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP has exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP has exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect but a different AMP is credited.

F Material not in NUREG-1801 for this component.

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

I Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-specific notes:

1 The CS Component asset was created to manage Boric Acid wastage of external surfaces only (for any carbon steel, low alloy steel, or cast iron component, including bolting), and therefore internal environments for this asset are not applicable. All other internal and external aging effects are identified separately under the specific component type.

2 Internal aging effects are not applicable. Due to the way data is entered into the LRDB, the internal environment of some components is listed as N/A (e.g. bolting, walls, clad vessels, structural steel, etc.).

3 Although the NUREG references a temperature gate of < 90 degrees C (200 degrees F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140 degrees F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The aging effect identified by PBNP (loss of material) for temperatures < 140 degrees F differs from that of the NUREG. That not withstanding, the Water Chemistry Control Program, which is credited

for managing the aging effects for all temperatures, will preclude the possibility of crack initiation and growth due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of the Chemistry program.

4 Plant specific program identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

5 Material/environment combination and/or aging effect not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

6 Program different than identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

7 There are no bolts with a specified minimum yield strength > 150 ksi in this system. Therefore, SCC is not an applicable aging effect/mechanism.

8 External aging effects are not applicable. Due to the way data is entered into the LRDB, the external environment of some components is listed as N/A (e.g. cladding, HX tubing, or other components that are entirely contained within another component).

9 AFW pump bearing coolers are integral to the bearing housing.

10 FE housing is CS but venturi is SS.

11 Internal portions of AFW turbine exhaust that are open to atmosphere.

12 Some components in this system experience a temperature below 200 degrees F, insufficient flow to support FAC, or operate less than 2% of the time. The components that fall in this category do not require aging management for FAC.

13 Some components are replaced on a specified frequency that precludes aging effects from resulting in loss of intended function. Periodic Surveillance and Preventive Maintenance Program is used to replace these components.

14 AFW Pump turbine casing's environment is more closely related to Main Steam environments, since it is not addressed in Chapter VIII.G Aux Feedwater System.

15 Components in this grouping do not have flow velocities >10 fps, and therefore loss of material due to erosion is not an aging effect requiring management.

16 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not

subject to temperatures where change in material properties or cracking could occur (>95 degrees F). Therefore no aging management is required.

17 SCC is not a concern for this material/environment group, due to temperatures being <140 degrees F.

18 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are subject to temperatures where change in material properties or cracking could occur (>95 degrees F).

19 Fuel Oil Chemistry Control Program is not necessary for managing the aging effects for a flame arrestor.

20 ISI inspections are not performed on this component, and therefore the ISI Program is not credited for managing the aging of this component.

21 Materials science supports loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The Water Chemistry Control Program is credited for managing the aging effects for all temperatures.

22 NUREG-1801 has loss of fracture toughness as an aging effect for this component. However, fluence levels for this component are below the threshold value, and therefore effects are not significant and do not require aging management.

23 NUREG-1801 credits the ISI Program for managing loss of material. PBNP does credit the ISI Program for managing cracking on this same component, and these inspections will identify loss of material/pitting, but only in the area of interest (at the weld). The Steam Generator Integrity Program is being included as it performs more general area inspections of the secondary side of the SGs. Previous visual inspections have confirmed no indications of loss of material.

24 This NUREG-1801 line item lists Loss of Material/Corrosion for the Aging Effect/Mechanism. This is interpreted to include the mechanisms of general and boric acid corrosion.

25 Tendon, loss of prestress NUREG-1801, line item 3.5.1-11/II.A1.3-b, is not addressed in this table. Refer to Section 4.0 on TLAAs.

26 No aging effects requiring management were identified for concrete (buried, indoor, or outdoor) and grout (except for Component Supports), however, concrete and grout is periodically monitored for potential degradation by an applicable license renewal program. See Appendix B for a discussion of the aging management programs used for concrete and grout.

27 Support (component or pipe) baseplates and their attachment to the structure (typically with embedded bolts or expansion anchors) are not within the scope of IWF and are considered

a part of the structure. However, for completeness, these items, including grout, are inspected when performing an IWF inspection. It is for this reason, that an ASME component support inspection will also be assigned against the Structures Monitoring Program.

28 The NUREG-1801 Volume I, line item 3.3.1-20, does not include the Control Building (Group 1 Structure), therefore, a comparable Group 3 Structure was chosen.

29 Doors that are assigned to the Structures Monitoring Program include those with the HELB function. Doors that are assigned to the Fire Protection Program include those with the fire or flood function. Note that some doors are common to both programs.

30 The Fire Barrier intended function is assigned to containment piping and electrical penetrations, fuel transfer tube, liner, and airlocks component types.

31 The fuel transfer tube is included with this component type (containment pressure boundary), therefore, the aging management program is appropriate.

32 Containment penetration sleeves, cracking/cyclic loading NUREG-1801, line item 3.5.1-2/II.A3.1-c, is not addressed in this table. Refer to Section 4.0 on TLAAs.

33 Crane, fatigue damage NUREG-1801, line item 3.3.1-3/VII.B.1-a, is not addressed in this table. Refer to Section 4.0 on TLAAs.

34 Consistent with NUREG-1801 for material, environment, aging effect and an additional AMP is credited.

35 Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter.

36 The material identified in this NUREG-1801 line item is stainless steel. The aging effects of stainless steel are the same as those for Cast Austenitic Stainless Steel at temperatures < 482 degrees F.

37 Unit 1 inspection port bolting has been identified by Westinghouse as being fatigue sensitive and needing replacement every 12 years. The Periodic Surveillance and Preventive Maintenance Program will be used to replace this bolting on a 10 year frequency.

38 The Unit 2 Steam Generators were designed and fabricated to eliminate the need for certain Section XI weld examinations. The Unit 2 transition cones are fabricated such that the girth welds are not at the discontinuity, and therefore Section XI does not require these welds to be periodically inspected. The steam nozzles were also fabricated integral to the elliptical head, and therefore there is no steam nozzle weld to inspect.

39 The One-Time Inspection is only for the letdown orifices, which is in response to NRC IN 98-045, “Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds.”

40 The Fuel Oil Chemistry Control Program includes provisions for performing tests/inspections for detecting tank wall loss.

41 In some cases where the Water Chemistry Control Program is not a viable option and aging effects are not expected to be significant, the One-Time Inspection Program alone is credited for managing aging effects. The One-Time Inspection Program has provisions to increase frequency of inspections based on the results of the first inspection.

3.5 Aging Management of Containments, Structures, and Component Supports

Applicability of Westinghouse WCAP-14756-A for PBNP Containment Structures

The Westinghouse Owners' Group Life Cycle Management & License Renewal Program has prepared topical report, WCAP-14756-A (Reference 1), Aging Management Evaluation for Pressurized Water Reactor Containment Structure, which has been utilized in the aging management review of the PBNP Containment Structures. Therefore, reconciliation of the final SER for WCAP-14756-A applicant action items is provided in Table 3.5.0-1. A description of aging management activities is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the Containment Structures will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Applicability of Westinghouse WCAP-14422, Rev. 2-A, for PBNP Reactor Coolant System Supports

The Westinghouse Owners' Group Life Cycle Management & License Renewal Program has prepared topical report, WCAP-14422, Rev. 2-A, License Renewal Evaluation: Aging Management for Reactor Coolant System Supports (Reference 2), which has been utilized in the aging management review of the PBNP RC System Supports components. The scope of the RC System supports components described in the topical report bounds the PBNP RC System Supports components.

A reconciliation of the final SER for WCAP-14422 Rev. 2-A applicant action items is provided in Table 3.5.0-2. A description of aging management activities is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the RC System Supports components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

3.5.1 Introduction

This section provides the results of the aging management review for those components identified in Section 2.4, Containments, Structures, and Component Supports, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section, are described in the indicated sections.

- Containment Unit 1/2 Building Structure (Section 2.4.1)
- Control Building Structure (Section 2.4.2)
- Circulating Water Pumphouse Structure (Section 2.4.3)
- Diesel Generator Building Structure (Section 2.4.4)
- Facade Unit 1/2 Structure (Section 2.4.5)
- Primary Auxiliary Building Structure (Section 2.4.6)
- Turbine Building Unit 1/2 Structure (Section 2.4.7)
- Yard Structures (Section 2.4.8)
- Cranes, Hoists, and Lifting Devices (Section 2.4.9)
- Component Supports Commodity Group (Section 2.4.10)
- Fire Barrier Commodity Group (Section 2.4.11)
- 13.8 KV Switchgear Building Structure (Section 2.4.12)
- Fuel Oil Pumphouse Structure (Section 2.4.13)
- Gas Turbine Building Structure (Section 2.4.14)

Table 3.5.1, Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports, provides the summary of the programs evaluated in NUREG-1801 for the Structures and Component Supports component groups that are relied on for license renewal.

This table uses the format described in Section 3.0 above. Note that this table only includes those component groups that are applicable to a PWR.

3.5.2 Results

The following tables summarize the results of the aging management review for systems in the Containments, Structures, and Component Supports group:

Table 3.5.2-1, Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Table 3.5.2-2, Structures and Component Supports - Control Building Structure - Summary of Aging Management Evaluation

Table 3.5.2-3, Structures and Component Supports - Circulating Water Pumphouse Structure - Summary of Aging Management Evaluation

Table 3.5.2-4, Structures and Component Supports - Diesel Generator Building Structure - Summary of Aging Management Evaluation

Table 3.5.2-5, Structures and Component Supports - Facade Unit 1/2 Structure - Summary of Aging Management Evaluation

Table 3.5.2-6, Structures and Component Supports - Primary Auxiliary Building Structure - Summary of Aging Management Evaluation

Table 3.5.2-7, Structures and Component Supports - Turbine Building Unit 1/2 Structure - Summary of Aging Management Evaluation

Table 3.5.2-8, Structures and Component Supports - Yard Structures - Summary of Aging Management Evaluation

Table 3.5.2-9, Structures and Component Supports - Cranes, Hoists, and Lifting Devices - Summary of Aging Management Evaluation

Table 3.5.2-10, Structures and Component Supports - Component Supports Commodity Group - Summary of Aging Management Evaluation

Table 3.5.2-11, Structures and Component Supports - Fire Barrier Commodity Group - Summary of Aging Management Evaluation

Table 3.5.2-12, Structures and Component Supports - 13.8 KV Switchgear Building Structure - Summary of Aging Management Evaluation

Table 3.5.2-13, Structures and Component Supports - Fuel Oil Pumphouse Structure - Summary of Aging Management Evaluation

Table 3.5.2-14, Structures and Component Supports - Gas Turbine Building Structure - Summary of Aging Management Evaluation

The materials that specific components are fabricated from, the environments to which components are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above systems in the following subsections of Section 3.5.2.1, Materials, Environment, Aging Effects Requiring Management and Aging Management Programs:

Section 3.5.2.1.1, Containment Unit 1/2 Building Structure

Section 3.5.2.1.2, Control Building Structure

Section 3.5.2.1.3, Circulating Water Pumphouse Structure

Section 3.5.2.1.4, Diesel Generator Building Structure

Section 3.5.2.1.5, Facade Unit 1/2 Structure

Section 3.5.2.1.6, Primary Auxiliary Building Structure

Section 3.5.2.1.7, Turbine Building Unit 1/2 Structure

Section 3.5.2.1.8, Yard Structures

Section 3.5.2.1.9, Cranes, Hoists, and Lifting Devices

Section 3.5.2.1.10, Component Supports Commodity Group

Section 3.5.2.1.11, Fire Barrier Commodity Group

Section 3.5.2.1.12, 13.8 KV Switchgear Building Structure

Section 3.5.2.1.13, Fuel Oil Pumphouse Structure

Section 3.5.2.1.14, Gas Turbine Building Structure

3.5.2.1 Materials, Environment, Aging Effects Requiring Management and Aging Management Programs

3.5.2.1.1 Containment Unit 1/2 Building Structure

Materials

The materials of construction for the Containment Unit 1/2 Building Structure components are:

- Carbon Steel Foundation Piles
- Concrete (Reinforced)
- Elastomer
- Grout
- Structural Copper Alloy (Zinc<15%)
- Structural Steel - Carbon
- Structural Steel - Stainless

Environment

The Containment Unit 1/2 Building Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Treated Water - Borated, T<140°F (External)

Aging Effects Requiring Management

The following aging effects, associated with the Containment Unit 1/2 Building Structure, require management:

- Change in Mat'l Properties due to Elevated Temp.
- Cracking due to Elevated Temperature
- Cracking due to Ultraviolet Radiation and Ozone
- Loss Of Material due to Boric acid Wastage
- Loss Of Material due to Crevice Corrosion
- Loss Of Material due to General Corrosion
- Loss Of Material due to MIC
- Loss Of Material due to Pitting Corrosion
- Loss of Material due to Wear

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Unit 1/2 Building Structure components:

- ASME Section XI, Subsections IWE & IWL Inservice Inspection Program
- Boric Acid Corrosion Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Water Chemistry Control Program

3.5.2.1.2 Control Building Structure

Materials

The materials of construction for the Control Building Structure components are:

- Block Wall
- Concrete (Reinforced)
- Elastomer
- Glass
- Grout
- Structural Cast Iron

- Structural Steel - Carbon
- Wood

Environment

The Control Building Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Control Building Structure, require management:

- Change in Mat'l Properties due to Elevated Temp.
- Change in Mat'l Properties due to Rot and Mildew
- Cracking due to Elevated Temperature
- Cracking due to restraint, shrinkage, etc.
- Cracking due to Ultraviolet Radiation and Ozone
- Loss Of Material due to General Corrosion
- Loss Of Material due to Rot and Mildew
- Loss Of Material due to Wear

Aging Management Programs

The following aging management programs manage the aging effects for the Control Building Structure components:

- Fire Protection Program
- Structures Monitoring Program

3.5.2.1.3 Circulating Water Pumphouse Structure

Materials

The materials of construction for the Circulating Water Pumphouse Structure components are:

- Concrete (Reinforced)
- Fiber Reinforced Cement

- Grout
- Structural Steel - Carbon

Environment

The Circulating Water Pumphouse Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)
- Raw Water (Submerged) (External)

Aging Effects Requiring Management

The following aging effects, associated with the Circulating Water Pumphouse Structure, require management:

- Loss Of Material due to Abrasion/Cavitation
- Loss Of Material due to General Corrosion
- Loss Of Material due to Wear

Aging Management Programs

The following aging management programs manage the aging effects for the Circulating Water Pumphouse Structure components:

- Fire Protection Program
- Structures Monitoring Program

3.5.2.1.4 Diesel Generator Building Structure

Materials

The materials of construction for the Diesel Generator Building Structure components are:

- Concrete (Reinforced)
- Grout
- Structural Steel - Carbon

Environment

The Diesel Generator Building Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Diesel Generator Building Structure, require management:

- Loss Of Material due to General Corrosion
- Loss Of Material due to Wear

Aging Management Programs

The following aging management programs manage the aging effects for the Diesel Generator Building Structure components:

- Fire Protection Program
- Structures Monitoring Program

3.5.2.1.5 Facade Unit 1/2 Structure

Materials

The materials of construction for the Facade Unit 1/2 Structure components are:

- Block Wall
- Concrete (Reinforced)
- Grout
- Structural Steel - Carbon

Environment

The Facade Unit 1/2 Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Facade Unit 1/2 Structure, require management:

- Cracking due to restraint, shrinkage, etc.
- Loss Of Material due to General Corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the Facade Unit 1/2 Structure components:

- Structures Monitoring Program

3.5.2.1.6 Primary Auxiliary Building Structure

Materials

The materials of construction for the Primary Auxiliary Building Structure components are:

- Block Wall
- Boraflex
- Carbon Steel Foundation Piles
- Concrete (Reinforced)
- Elastomer
- Grout
- Structural Steel - Carbon
- Structural Steel - Stainless

Environment

The Primary Auxiliary Building Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)
- Treated Water - Borated, T<140°F (External)

Aging Effects Requiring Management

The following aging effects, associated with the Primary Auxiliary Building Structure, require management:

- Change in Mat'l Properties due to Elevated Temp.
- Cracking due to Elevated Temperature
- Cracking due to restraint, shrinkage, etc.
- Cracking due to Ultraviolet Radiation and Ozone
- Loss Of Material due to Boric Acid Wastage
- Loss Of Material due to Crevice Corrosion
- Loss Of Material due to General Corrosion
- Loss Of Material due to MIC
- Loss Of Material due to Pitting Corrosion
- Loss Of Material due to Wear
- Red. of Neutron-Absorb. Cap./Boraflex Degrad.

Aging Management Programs

The following aging management programs manage the aging effects for the Primary Auxiliary Building Structure components:

- Boraflex Monitoring Program
- Boric Acid Corrosion Program
- Fire Protection Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Water Chemistry Control Program

3.5.2.1.7 **Turbine Building Unit 1/2 Structure**

Materials

The materials of construction for the Turbine Building Unit 1/2 Structure components are:

- Block Wall
- Concrete (Reinforced)

- Grout
- Structural Steel - Carbon

Environment

The Turbine Building Unit 1/2 Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Turbine Building Unit 1/2 Structure, require management:

- Cracking due to restraint, shrinkage, etc.
- Loss Of Material due to General Corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine Building Unit 1/2 Structure components:

- Structures Monitoring Program

3.5.2.1.8 Yard Structures

Materials

The materials of construction for the Yard Structures components are:

- Concrete (Reinforced)
- Structural Cast Iron
- Structural Steel - Carbon
- Earth

Environment

The Yard Structures components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Yard Structures, require management:

- Loss Of Material due to General Corrosion
- Loss Of Material due to Selective Leaching
- Loss of Material due to Surface Runoff and Erosion

Aging Management Programs

The following aging management programs manage the aging effects for the Yard Structures components:

- Structures Monitoring Program

3.5.2.1.9 Cranes, Hoists, and Lifting Devices

Materials

The materials of construction for the Cranes, Hoists, and Lifting Devices components are:

- Structural Steel - Carbon
- Structural Steel - Stainless

Environment

The Cranes, Hoists, and Lifting Devices components are exposed to the following environments:

- Indoor - No Air Conditioning (External)
- Treated Water - Borated, T<140°F (External)

Aging Effects Requiring Management

The following aging effects, associated with the Cranes, Hoists, and Lifting Devices, require management:

- Loss Of Material due to Crevice Corrosion
- Loss Of Material due to General Corrosion
- Loss Of Material due to MIC
- Loss Of Material due to Pitting Corrosion
- Loss Of Material due to Wear

Aging Management Programs

The following aging management programs manage the aging effects for the Cranes, Hoists, and Lifting Devices components:

- Structures Monitoring Program

3.5.2.1.10 Component Supports Commodity Group

Materials

The materials of construction for the Component Supports Commodity Group components are:

- Elastomer
- Grout
- Structural Steel - Carbon
- Structural Steel - Stainless

Environment

The Component Supports Commodity Group components are exposed to the following environments:

- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Component Supports Commodity Group, require management:

- Change in Mat'l Properties due to Elevated Temp.
- Cracking due to Elevated Temperature
- Cracking due to Service Induced Loadings
- Cracking due to Ultraviolet Radiation and Ozone
- Loss Of Material due to Boric Acid Wastage
- Loss Of Material due to General Corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the Component Supports Commodity Group components:

- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boric Acid Corrosion Program
- Structures Monitoring Program

3.5.2.1.11 Fire Barrier Commodity Group

Materials

The materials of construction for the Fire Barrier Commodity Group components are:

- Calcium Silicate Board
- Ceramic Fiber
- Ceramic Fiber Board
- Ceramic Fiber Mat
- Silicone Based Materials
- Stainless Steel
- Structural Steel - Carbon

Environment

The Fire Barrier Commodity Group components are exposed to the following environments:

- Indoor - No Air Conditioning (External)

Aging Effects Requiring Management

The following aging effects, associated with the Fire Barrier Commodity Group, require management:

- Cracking/Delamination due to Movement
- Cracking/Delamination due to Shrinkage
- Cracking/Delamination due to Vibration
- Increased Hardness and Shrinkage due to Weathering
- Loss Of Material due to Abrasion
- Loss Of Material due to Flaking

- Loss Of Material due to General Corrosion
- Separation due to Movement
- Separation due to Shrinkage
- Separation due to Vibration

Aging Management Programs

The following aging management programs manage the aging effects for the Fire Barrier Commodity Group components:

- Fire Protection Program

3.5.2.1.12**13.8 KV Switchgear Building Structure**

Materials

The materials of construction for the 13.8 KV Switchgear Building Structure components are:

- Concrete (Reinforced)

Environment

The 13.8 KV Switchgear Building Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the 13.8 KV Switchgear Building Structure, require management:

- None

Aging Management Programs

The following aging management programs manage the aging effects for the 13.8 KV Switchgear Building Structure components:

- Structures Monitoring Program

3.5.2.1.13 **Fuel Oil Pumphouse Structure**

Materials

The materials of construction for the Fuel Oil Pumphouse Structure components are:

- Concrete (Reinforced)

Environment

The Fuel Oil Pumphouse Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Fuel Oil Pumphouse Structure, require management:

- None

Aging Management Programs

The following aging management programs manage the aging effects for the Fuel Oil Pumphouse Structure components:

- Structures Monitoring Program

3.5.2.1.14 **Gas Turbine Building Structure**

Materials

The materials of construction for the Gas Turbine Building Structure components are:

- Concrete (Reinforced)

Environment

The Gas Turbine Building Structure components are exposed to the following environments:

- Buried (External)
- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Gas Turbine Building Structure, require management:

- None

Aging Management Programs

The following aging management programs manage the aging effects for the Gas Turbine Building Structure components:

- Structures Monitoring Program

3.5.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

NUREG-1801 Volume 1 Tables provide the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Containments, Structures, and Component Supports, those programs are addressed in the following sections.

3.5.2.2.1 PWR Containment

3.5.2.2.1.1 Aging of Inaccessible Concrete Areas

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program identifies that an aging mechanism is present and active and also provides confirmation and verification of the absence of all types of aging effects. Aging effects may be absent if the materials of construction, design specifications, and operational environment preclude an aging mechanism but, it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is applicable. The degradation of inaccessible concrete can create symptoms of aging effects that are detectable in accessible areas. Conversely, if aging effects are present in accessible areas it is sensible to extrapolate those effects into inaccessible areas and perform additional evaluations.

Containment accessible and inaccessible concrete has been evaluated for the following aging mechanisms:

Aging Mechanism: Aggressive Chemical Attack
Aging Effect: Loss of Material, Changes in Material Properties
Evaluation: Concrete degradation in air due to aggressive rainwater is insignificant and the below-grade/lake water environment is

non-aggressive, therefore, loss of material and change in material properties due to aggressive chemical attack are not probable aging effects at Point Beach and have not been observed to date. The Structures Monitoring Program requires periodic monitoring of ground/lake water to verify chemistry remains non-aggressive.

Aging Mechanism: Corrosion of Embedded Steel
Aging Effect: Loss of Material, Cracking, Loss of Bond
Evaluation: Since the embedded steel is not exposed to an environment which is considered aggressive, loss of material, cracking, and loss of bond due to corrosion of embedded steel are not probable aging effects at Point Beach and have not been observed to date.

Aging Mechanism: Leaching of Calcium Hydroxide
Aging Effect: Change in Material Properties
Evaluation: The original construction specifications met the intent of ACI 201.2R. Change in material properties due to leaching of calcium hydroxide is not a probable aging effect at Point Beach and has not been observed to date.

Operating experience has shown that concrete has not experienced unanticipated aging effects at Point Beach. That notwithstanding, the identification of the above aging effects by the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program, as well as the resistance provided by the materials of construction provide adequate assurance that all types of concrete aging effects will be identified and managed through out the extended period of operation.

3.5.2.2.1.2 **Cracking, Distortion, and Increase in Component Stress Level due to Settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program**

Cracks, distortion, and increase in component stresses due to settlement of concrete foundations are considered in the Structures Monitoring Program. All structures at Point Beach are either founded on spread footings, basemats, or basemats with steel foundation piles that are driven to refusal. Settlement monitoring and structural inspections indicate no visible evidence of uneven or excessive settlement since construction of the station. Cracking, distortion, and an increase in component stress levels due to settlement are not probable aging effects at Point Beach and have not been observed to date. That notwithstanding, the Structures Monitoring Program monitors for cracks and distortion and contains inspection criteria to verify these aging effects are not developing.

Reduction in foundation strength due to erosion of porous concrete subfoundations is not an aging effect requiring management at PBNP. Point Beach's structure foundations are constructed of normal concrete and not the subject porous type, nor are foundations subject to flowing water. That notwithstanding, the Structures Monitoring Program monitors for settlement and cracking. The identification of indications of settlement by the Structures Monitoring Program, as well as the resistance provided by the materials of construction, provide adequate assurance that reductions in foundation strength for any reason will be identified and managed through out the extended period of operation.

3.5.2.2.1.3 Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature

For plant areas of concern, temperatures are normally maintained below the specified limits; therefore, loss of material, cracking, and change in material properties due to elevated temperature is not an aging effect requiring management at Point Beach. (Note: The concrete surrounding the hot containment penetrations are insulated to limit the concrete temperature and the reactor cavity cooling sub-system maintains acceptable ambient temperature at the primary shield and reactor vessel support structure). That notwithstanding, the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program and the Structures Monitoring Program monitor for loss of material, cracks, and changes in material properties and contains inspection criteria to verify these aging effects are not developing.

3.5.2.2.1.4 Loss of Material due to Corrosion in Inaccessible Areas of Steel Containment Shell or Liner Plate

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program includes inspections and leak rate tests which would indicate the presence of significant degradation due to loss of material from all applicable corrosion mechanisms. Plant operating experience has shown that borated water spills in containment have impacted the containment liner. Accordingly, the containment liner plate has been selected to receive augmented examinations, category E-C, in accordance with ISI IWE.

Additionally, the Boric Acid Corrosion Program is also credited with assessing and managing loss of material in the containment liner.

3.5.2.2.1.5 Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). Loss of prestress is addressed as a TLAA in Section 4.5.

3.5.2.2.1.6 Cumulative Fatigue Damage

If included in the current licensing basis, fatigue analyses of containment steel liner plates and steel containment shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header and downcomers are TLAAs 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 separately in Section 4.3.11.

A fatigue review of penetration sleeves is contained in the Point Beach CLB and has been evaluated as a TLAA (see Section 4.3.11). However, penetration bellows and dissimilar metal welds are not incorporated into Point Beach's current licensing basis as TLAAs.

3.5.2.2.1.7 Cracking due to Cyclic Loading and SCC

The PBNP liner penetrations have had a fatigue review and are bounded by line item 3.5.1-01/II.A3.1-b. Therefore, cracking due to cyclic loading is not addressed here (see TLAA Section 4.3.11 for details). SCC is not an applicable aging mechanism for penetration sleeves, bellows and dissimilar metal welds. The carbon steel components within penetrations are not susceptible to SCC. The stainless steel components require both a high temperature (>140°F) and exposure to an aggressive chemical environment (e.g. exposure to chlorides). The bellows at Point Beach are not exposed to aggressive chemical environments. A review of plant specific operating experience did not identify any occurrences of bellows failures due to SCC. Furthermore a review of industry operating experience indicated that SCC of bellows was typically caused by poor design controls leading to the inadvertent introduction of contaminants.

3.5.2.2.2 Class 1 Structures

3.5.2.2.2.1 Aging of Structures Not Covered by Structures Monitoring Program

The Structures Monitoring Program identifies that an aging mechanism is present and active and also provides confirmation and verification of the absence of all types of aging effects. Aging effects may be absent if the materials of construction, design specifications, and operational environment preclude an aging mechanism but, it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is applicable.

Accessible interior and exterior concrete have been evaluated for the following aging mechanisms:

Aging Mechanism: Freeze-Thaw
Aging Effect: Loss of Material
Evaluation: The contract-specified air contents are within the range specified by ACI 318-63, and the contract-specified water-to-cement ratio meets the recommendations of ACI 318-63. Therefore, loss of material and cracking of concrete due to freeze-thaw are not probable aging effects at Point Beach and have not been observed to date.

Aging Mechanism: Elevated Temperature
Aging Effect: Loss of Material, Cracking, Changes in Material Properties
Evaluation: For plant areas of concern, temperatures are normally maintained below the specified limits; therefore, loss of material, cracking, and change in material properties due to elevated temperature are not probable aging effects at Point Beach and have not been observed to date.

Aging Mechanism: Aggressive Chemical Attack
Aging Effect: Loss of Material, Changes in Material Properties
Evaluation: Concrete degradation in air due to aggressive rainwater is insignificant and the below-grade/lake water environment is non-aggressive; therefore, loss of material and change in material properties due to aggressive chemical attack are not probable aging effects at Point Beach and have not been observed to date. The Structures Monitoring Program requires periodic monitoring of ground/lake water to verify chemistry remains non-aggressive.

Aging Mechanism: Corrosion of Embedded Steel
Aging Effect: Loss of Material, Cracking, Loss of Bond
Evaluation: Since the embedded steel is not exposed to an environment

which is considered aggressive, loss of material, cracking, and loss of bond due to corrosion of embedded steel are not probable aging effects at Point Beach and have not been observed to date.

Aging Mechanism: Reaction with Aggregates
Aging Effect: Cracking, Expansion
Evaluation: During construction the aggregates were tested for potential reactivity in accordance with ASTM C227 and ASTM C295, cracking and expansion due to reaction with aggregates are not probable aging effects at Point Beach and have not been observed to date.

Aging Mechanism: Settlement
Aging Effect: Cracking, Distortion, Increase in Component Stress Level
Evaluation: All structures at Point Beach are either founded on spread footings, basemats, or basemats with steel foundation piles that are driven to refusal. Settlement monitoring and structural inspections indicate no visible evidence of uneven or excessive settlement since construction of the station. Cracking, distortion, and an increase in component stress levels due to settlement are not probable aging effects at Point Beach and have not been observed to date.

Aging Mechanism: Leaching of Calcium Hydroxide
Aging Effect: Change in Material Properties
Evaluation: The original construction specifications met the intent of ACI 201.2R. Change in material properties due to leaching of calcium hydroxide is not a probable aging effect at Point Beach and has not been observed to date.

Operating experience has shown that concrete has not experienced unanticipated aging effects at Point Beach. That notwithstanding, the identification of the above aging effects by the Structures Monitoring Program, as well as the resistance provided by the materials of construction provide adequate assurance that all types of concrete aging effects will be identified and managed through out the extended period of operation.

Accessible interior and exterior steel components have been evaluated for the following aging mechanisms:

Aging Mechanism: General Corrosion
Aging Effect: Loss of Material
Evaluation: Carbon and low-alloy steel surfaces, which are exposed to

typical plant environments, can experience general corrosion. Additionally, structural steel can be subject to boric acid corrosion.

Operating experience has shown that corrosion of accessible interior and exterior structural steels is an aging effect that requires management at Point Beach. Accordingly, the Structures Monitoring Program identifies and evaluates corrosion of interior and exterior structural steel. Additionally, accessible carbon low alloy structural steel located in areas that contain borated water systems are subject to the requirements of Boric Acid Corrosion Program.

3.5.2.2.2.2 Aging Management of Inaccessible Areas

Concrete degradation in air due to aggressive rainwater is insignificant and the below-grade/lake water environment is non-aggressive, therefore, loss of material and change in material properties due to aggressive chemical attack are not probable aging effects at Point Beach and have not been observed to date. The Structures Monitoring Program requires periodic monitoring of ground/lake water to verify chemistry remains non-aggressive.

Since the embedded steel is not exposed to an environment which is considered aggressive, loss of material, cracking, and loss of bond due to corrosion of embedded steel are not probable aging effects at Point Beach and have not been observed to date.

3.5.2.2.3 Component Supports

3.5.2.2.3.1 Aging of Supports Not Covered by Structures Monitoring Program

The aging effects associated with component supports are considered in the Structures Monitoring Program. Component supports include those structural elements that are connected to the building or its structures and which extend to a system or system components for the purpose of providing support or restraint. Inclusive in this boundary definition are any vibration dampeners. The group also includes spray or drip shields attached to equipment as well as electrical system racks, panels and enclosures. Component supports are located throughout the plant. Included in the evaluation of the component supports are supports for both safety related components and non-safety related components whose failure could affect a safety function (typically referred to as seismic II/I).

Component supports including support members; anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc. have been evaluated for the following specific aging mechanisms:

Aging Mechanism: Service-induced cracking or other concrete aging mechanisms
Aging Effect: Reduction in concrete anchor capacity due to local concrete degradation
Evaluation: Operating experience has shown that service induced cracking can occur in grouted foundations. Concrete expansion bolts (anchors) can lose anchor capacity due to local concrete degradation or localized concrete distress. The Structures Monitoring Program identifies and evaluates cracking and other concrete aging mechanisms for component supports.

Aging Mechanism: Degradation of vibration isolation elements
Aging Effect: Reduction/loss of isolation function
Evaluation: Operating experience has shown that elastomer materials can degrade over time. The Structures Monitoring Program identifies and evaluates the degradation of vibration isolation elements.

3.5.2.2.3.2 Cumulative Fatigue Damage due to Cyclic Loading

Fatigue of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports is a TLAA 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 separately in Section 4.3.

A fatigue analysis for structures and component supports is not incorporated into Point Beach's current licensing basis. Consequently, this line item is not applicable to Point Beach.

3.5.2.3 Time-Limited Aging Analysis

The time-limited aging analyses (TLAA) identified below are associated with the Containments, Structures, and Component Supports components. The section of the LRA that contains the TLAA review results is indicated in parenthesis.

- Fatigue (Section 4.3.11, Containment Liner Plate Fatigue Analysis)
- Fatigue (Section 4.3.13, Crane Load Cycle Limit)

- Loss of Preload (Section 4.5.1, Containment Tendon Loss of Prestress Analysis)
- Neutron Absorber (Section 4.6.1, Spent Fuel Pool Storage Rack Boraflex)

3.5.3 Conclusion

The Containments, Structures, and Component Supports 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 Containments, Structures, and Component Supports components are identified in the summaries in Section 3.5.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the Containments, Structures, and Component Supports components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(1) The license renewal applicant will (i) verify that its plant is bounded by the GTR, (ii) commit to implement programs described as necessary in the GTR to manage the effects of aging during the period of extended operation, and (iii) verify that the programs committed to are conducted in accordance with appropriate regulatory controls (e.g. 10 CFR Part 50, Appendix B). Further, the renewal applicant will identify any deviations from the aging management programs which this GTR describes as necessary to manage the effects of aging during the period of extended operation or to maintain the functionality of the containment structure, and deviations from other information presented in the GTR (e.g., materials of construction). The renewal applicant will evaluate any such deviations in accordance with 10 CFR 54.21(a)(3) and (c)(1) on a plant-specific basis. The following functions, which are specific to containment structures and are understood to be covered by the various intended functions, should be addressed explicitly in the license renewal application: (1) providing structural or functional support of safety related systems, structures, and components following a design basis accident (DBA); (2) serving as an external missile barrier consistent with the design and licensing basis; and (3) providing passive heat sinks during a DBA or station blackout in addition to the spray system.	The design, configuration, materials of construction, and normal operating service environment of the Point Beach Nuclear Plant (PBNP) Containment structure are bounded by the GTR. As part of license renewal, the PBNP aging management programs will implement the programs described in the GTR as necessary to manage the effects of aging during the period of extended operation. Further, the programs committed to will be conducted in accordance with appropriate regulatory controls (e.g., 10 CFR 50, Appendix B). The GTR evaluated aging of the pressurized water reactor containment structure to ensure that the intended functions will be maintained during the extended period of operation. Four intended functions performed by the PWR containment structure are identified in the GTR. • Ensuring the integrity of the reactor coolant pressure boundary (RCPB). • Ensuring the capability to perform a shut down of the reactor and maintain it in a safe shutdown condition. • Ensuring the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR 100 guidelines. • Ensuring compliance with the USNRC regulations for environmental qualification (10 CFR 50.49). Three additional intended functions are identified in Action Item Number 1. These additional intended functions are indirectly addressed in the GTR aging management

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(1) (continued)	evaluation and aging management options since they are a subset of the four given in the GTR. Specifically, each of the additional intended functions are subsets of the following: • The additional intended function (1), providing structural or functional support of safety related systems, structures, and components following a design basis accident (DBA), is a subset of the GTR intended function 3. • The additional intended function (2), serving as an external missile barrier consistent with the design and licensing basis, is a subset of GTR intended functions 3 and 4. • The additional intended function (3), providing passive heat sinks during a DBA or station blackout in addition to the spray system, is a subset of GTR intended functions 2 and 3. Therefore, there is no need to further address the added functions in the license renewal application.
(2) A summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs is to be provided in the license renewal FSAR supplement, in accordance with 10 CFR 54.21(d).	A summary description of aging management programs credited for managing the effects of aging and evaluation of the TLAAs for the PBNP Containment Structure is provided in Appendix A of the LRA.
(3) Individual plant applicants will need to provide a comprehensive list of structures and components subject to an aging management review and the methodology used to develop this list as part of their license renewal applications. Any components determined by the applicant to be subject to an aging management review for license renewal but not within the scope of the GTR are required to be addressed in the license renewal application.	A comprehensive list of the structures and components subject to aging management review was developed in accordance with the methodology described in plant procedures. This list is available for on-site review.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(4) Provide cross-section drawings for the containment structures, and detailed drawings of the sand pocket region and other plant-specific features, if applicable.	Drawings showing the cross-section of the PBNP Containment structure and other specific features, including the sand-box region, are available at the plant site for review.
(5) Provide legible drawings of equipment and penetration details as part of the description of the containment structure components	Drawings of equipment and penetration details of the PBNP Containment structure are available at the plant site for review.
(6) For prestressed concrete containments, indicate whether the tendon access gallery is included as a containment structure component subject to an aging management review. If it is, provide the details of the aging management review and the credited aging management program. If not, provide a technical basis for its exclusion, addressing the potential for degradation of the lower vertical tendon anchors resulting from the environmental conditions in the tendon access gallery.	At PBNP, the vertical tendon anchorage is part of the 10 ft thick basemat of the containment structure. The tendon anchorage point is recessed into the basemat bottom side, therefore, the top few feet of the access gallery is in fact part of the basemat The remaining portion of the access gallery is not associated with the basemat. As such, the IWL inspection boundary includes the tendon gallery ceiling and a few feet down the inside and outside walls. The aging management program for this structural area is the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(7) Discuss plant-specific operating experience relevant to age-related degradation of containment structure components and how this experience has been considered in the aging management review.	PBNP operating experience was reviewed to validate the identified aging effects requiring management. Sources included Semi-annual and Annual Reports to AEC/NRC, Abnormal Occurrence and Licensee Event Reports (LERs), Non-Conformance Reports (NCRs), Corrective Action documents (CAs), Root Cause Evaluations, Fire Protection Evaluation Report and Action Requests (ARs) from initial operation to the present. In addition, plant-specific response to any NRC generic communication was reviewed for applicability. The results of NRC required ASME Section XI, Subsections IWE/IWL inspections were also reviewed. No additional or unique aging effects requiring management were identified from this review beyond those identified in the GTR and are listed inTable 3.5.2-1 of the LRA.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(8) For concrete containments, verify that the original plant design and construction specifications satisfy the criteria which are relied upon to exclude leaching of calcium hydroxide and reaction with aggregates as significant aging mechanisms. If these mechanisms are not excluded, describe the aging management program (AMP) which is credited to manage the aging effects associated with these aging mechanisms.	Leaching of Calcium Hydroxide Leaching of calcium hydroxide from reinforced concrete becomes significant only if the concrete is exposed to flowing water or hydraulic pressure. Even if reinforced concrete is exposed to flowing water, such leaching is not significant if the concrete is constructed to ensure that it is dense, well cured, has low permeability, and that cracking is well controlled. Cracking is controlled through proper arrangement and distribution of reinforcing bars. All of the above characteristics are assured if the concrete was constructed with the guidance of ACI 201.2R-77. PBNP concrete was constructed meeting the intentions of ACE 201.2R. The reinforced concrete of the Containment structure (base mat, ring beam and cylinder walls) is not exposed to flowing water or minimal hydraulic pressure. The entire containment structure of the PBNP is housed in an enclosure (façade structure) that provides protection from the weather. Flowing water or moisture penetration is not present. Reaction with Aggregates The Bechtel containment concrete specification was evaluated to assure compliance with NRC NUREG-1801 Report criteria. The concrete testing specification of aggregate for potential reactivity was performed in accordance with the ASTM C227 and C295 specifications contained in the NRC NUREG-1801 Report. Degradation due to reaction with aggregates is not an aging effect requiring management at PBNP. This evaluation is documented in the License Renewal Technical Report “Aging Mechanisms / Effects Applicability Evaluation, Concrete.”

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(8) (continued)	These facts notwithstanding, the current mandated inspections performed in accordance with the requirements of 10 CFR 50.55a and ASME Code Section XI, Subsection IWL, Examination Category L-A, and the Structures Monitoring Program would detect concrete aging effects. Leaching of calcium hydroxide and reaction with aggregates would be detected during the period of extended operation should they occur.
(9) For concrete containments, discuss whether local heating of containment concrete at the main steam and/or any other penetrations results in sustained concrete temperatures exceeding 200°F. If this condition exists, provide an aging management review and describe the credited aging management program.	The only lines penetrating the containment shell normally having high temperatures are the main steam and feedwater lines. For these lines, steady state temperature gradients were designed for the case with no cooling and with maximum insulation. The results indicate that local heating of containment concrete is considerably below the limit of 200°F (ASME Section III, Division 2 Subsection CC-3340) and active cooling for these penetrations is not required.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(10) Identify the codes, edition and/or date of codes and standards which govern plant containment design, inspection and repair.	The design, materials, fabrication, inspection, and proof testing of the containment complied with the applicable parts of the following codes and standards: 1. ASME Boiler and Pressure Vessel Code, Section III - Nuclear Vessels (mostly 1965 Edition; 1968 Edition and all Addenda was used for the design, fabrication, inspection, and testing of the Class B containment penetration head fittings); Section VIII - Unfired Pressure Vessels; Section IX - Welding Qualifications. 2. ACI 318-63, Building Code Requirements for Reinforced Concrete 3. American Institute of Steel Construction Specifications: a. Specifications for the Design, Fabrication, and Erection of Structural Steel for Buildings, (April, 1963). b. Code of Standard Practice for Steel Buildings and Bridges, (February 64). 4. USAS N 6.2 - 1965, Safety Standard for Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors. 5. ACI 306-66, Specifications for Structural Concrete for Buildings. 6. ASTM C 150- 65, Specifications for Portland Cement. 7. ASTM C 260- 66T, Specifications for Air-Entrained Admixtures for Concrete. 8. ASTM A 15-64, Specifications for Billet-Steel Bars for Concrete Reinforcement.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(10) (continued)	9. ASTM A572-66, Specification for High Strength Low Alloy Colombian Vanadium Steel of Structural Quality. 10. TID 7024 August 1963, Nuclear Reactors and Earthquakes. Additional codes and standards governing design, materials, inspection and repair for the PBNP Containment Structure are listed in Section 5.1.1 of the FSAR

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(11) Specify whether freeze-thaw is an applicable aging mechanism which will be managed by AMP 5.1 or AMP 5.2, as applicable. If not, provide the technical basis for exclusion.	According to NUREG-1801, freeze-thaw does not cause loss of material from reinforced concrete in foundations and in above and below-grade exterior concrete for plants located in a geographic region of negligible weathering conditions (weathering index <100 day-inch/yr). Loss of material from such concrete is not significant at plants located in areas where weathering conditions are severe (weathering index >500 day-inch/yr) or moderate (100-500 day-inch/yr) provided that the concrete mix design meets the air content (entrained air 3-6%) and water-to-cement ratio (0.35-0.45) specified in ACI 318-63 or ACI 349-85. PBNP is located in a severe weathering region. Construction of the Containment at PBNP was performed under Bechtel contract, Specification 6118-C-2. Since the contract specified air content was within the range specified by current revisions of ACI 318 and is within the range required by the NUREG-1801 report (3-6%), and the contract-specified water-to-cement ratio meets the recommendations of ACI 318-63, loss of material and cracking of concrete due to freeze-thaw is not an applicable aging mechanism requiring management at PBNP. Further, freeze-thaw damage for the PBNP containment is not a concern since the entire containment buildings are protected by the facade structure. Moisture penetration is not present. Nevertheless, the current mandated inspections performed in accordance with the requirements of 10 CFR 50.55a and the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program and the Structures Monitoring Program, would detect concrete aging effects. Freeze-thaw would be detected during the period of extended operation should it occur.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(12) Specify whether aggressive chemical attack is an applicable aging mechanism which will be managed by AMP 5.3 or AMP 5.4, as applicable. If not, provide the technical basis for exclusion.	NUREG-1801 provides guidance for determining whether aggressive chemical attack is an applicable aging mechanism for concrete structures. This guidance includes threshold values for the pH of the environment, and chloride and sulfate concentrations. The environments of concern are air (as influenced by rainwater), below-grade (as influenced by soil or groundwater) and lake water. These three environments are in direct contact with structures and components within the scope of license renewal. According to NUREG-1801, aggressive chemical attack is not significant if the concrete is not exposed to an aggressive environment. An aggressive environment is defined as pH <5.5, or >500 ppm chlorides, or >1500 ppm sulfates. The below-grade ground water and lake water environments, as determined from periodic tests of ground water and lake water at PBNP, are significantly less severe than the NUREG-1801 values. Therefore, chemical attack at the PBNP is classified as non-aggressive. Further, the air environment (as influenced by rainwater) for the PBNP containment is not a concern since the entire containment buildings are protected by the facade structure. Moisture wetting or penetration does not occur. These facts notwithstanding, the current mandated inspections performed in accordance with the requirements of 10 CFR 50.55a and ASME Code Section XI, Subsection IWL Inservice Inspection Program, would detect concrete aging effects.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(13) Provide details of the groundwater monitoring program and discuss potential seasonal variation in ground water chemistry.	The ground water level at PBNP is monitored at four monitoring wells located within the facade structure around the containment buildings. Ground water levels and water samples are periodically collected and analyzed. Although there were variations in the recorded water levels, they do not appear to be caused by seasonal effects. The ground water chemistry does not appear to vary by season. There is no permanent dewatering system at PBNP.
(14) For prestressed concrete containments, discuss plant experience with respect to tendon grease leakage and, if applicable, how the leakage will be managed; also discuss the potential effects of grease leakage on the shear load capacity of the containment structure.	Grease leakage is typically only a housekeeping issue since paraffin and petroleum based products have little effect on concrete. Grease leakage on concrete may be through a crack. Previous grease leakage indications on concrete are a result of leakage from the tendon sheathing through concrete cracks. Other historical leakage is at the tendon grease cap seals. The concern is the loss of the corrosion protection medium to a tendon. Containment visual inspections will identify and record indications in compliance with 10 CFR 50.55a. Also, the facade structure provides added protection from the intrusive effects of the environment. Management of grease leakage is accomplished by the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program. This program includes an integrated tendon surveillance that manages the tendon corrosion protection medium (grease leakage). Further, since the aging management program follows NRC accepted inspection and maintenance procedures for prestressing systems, that also include the management of tendon grease leakage, there will be no detrimental effect on the shear load capacity of the containment structure due to grease leakage effects.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(15) Each license renewal applicant needs to describe its plant-specific program to address the stress corrosion cracking (SCC) for dissimilar metal welds, and for stainless steel bellows assemblies, if the material is not shielded from a corrosive environment. For the period of extended operation, ASME Section XI, IWE examination Categories E-B and E-F and augmented VT-1 visual examination of bellows assemblies and dissimilar metal welds are required or a suitable alternative proposed.	Dissimilar metal welds and stainless steel bellows assemblies at PBNP are exposed to an internal air environment by virtue of the facade structure (external surfaces) and various process fluids (internal surfaces). These environments are not corrosive. Stainless steel components exposed to these environments are not susceptible to stress corrosion cracking (SSC), therefore cracking due to SCC is not an aging effect requiring management for dissimilar metal welds and stainless steel bellows assemblies. Plant-specific operating experience at PBNP confirms this conclusion. Nevertheless, the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program, which includes visual examinations (Category E-A), will be implemented at PBNP.
(16) Discuss the plant-specific coatings monitoring and maintenance program and specify whether it is credited as an AMP for containment steel elements.	While it is recognized that coatings provide protection to metal surfaces, coatings themselves are not credited at PBNP for management of aging effects since they perform no license renewal intended function. Degradation of coatings typically is a function of its environment. As coatings degrade, the metal surfaces to which they are applied also degrade. Aging management is accomplished by assessing the integrity of the metal surfaces. If degradation of a coated steel component is identified, corrective action includes repair or reapplication of the coating. Aging effects associated with aggressive environments are managed by the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(17) For prestressed concrete containments, specify whether post-tensioning system degradation will be managed by AMP 5.6 (Section XI, Subsection IWL, Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants, Examination Category L-B, Unbonded Post-Tensioning System, 1992 Code Edition with 1992 Addenda of the ASME Code) and the additional requirements delineated in 10 CFR 50.55a(b)2(ix). If not, provide the technical basis for exclusion.	Degradation of the post tensioning sub-system at PBNP will be managed in accordance with the requirements of ASME Section XI, Subsection IWL, Category L-B, 1992 Edition with 1992 Addenda along with the additional requirements delineated in the amendment to 10 CFR 50.55a (see SECY-96-080). The aging management program for tendons is the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program.
(18) Specify whether settlement of the containment foundation is an applicable aging mechanism which will be managed by AMP 5.7. If not, provide the technical basis for exclusion.	Settlement of structures is directly related to the physical properties of the foundation material. For structures located on a suitable foundation, any settlement should have occurred during or immediately following construction. The PBNP containment concrete base slab is reinforced with high strength steel and the slab is founded on H-piles driven to the underlying bedrock. Structural inspections indicate no evidence of excessive containment building settlement since construction of the PBNP. Therefore, settlement is not an applicable aging mechanism for the Containment structure concrete components. This notwithstanding, the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program and the Structures Monitoring Program effectively manage aging effects due to settlement of the Containment structure during the period of extended operation.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(19) Identify whether erosion of the porous concrete sub-foundation layer is an applicable aging mechanism; if applicable, provide an aging management review and describe the credited aging management program.	The NRC has issued Information Notices (IN) 97-11 and 98-26 informing nuclear facilities of the possibility of degradation to structure foundations due to the erosion of porous concrete sub-foundations. Per NUREG-1801, erosion of porous concrete sub foundations must be analyzed. According to the PBNP's review of NRC INs 97-11 and 98-26, the structure foundations at PBNP are constructed of normal concrete and not of the subject porous type. PBNP is not one of the nine nuclear plants identified by the NRC in October 1996 as having the potential of degradation due to porous concrete. Since porous concrete is not used at the PBNP, erosion of porous concrete sub-foundations is not an applicable aging mechanism.
(20) The GTR listed only six (6) attributes to form the basis for each aging management program. However, the “Draft Standard Review Plan for the Review of License Renewal applications for Nuclear Power Plans,” dated April 21, 2000, identifies ten (10) elements (attributes) as appropriate for an acceptable AMP. The GTR predates the Draft standard Review Plan for the review of Licensing Renewal applications for Nuclear Power Plans, and states in Section 4.0 that the report only presents program attributes for the AMPs, and that plant-specific details of the AMPs will be developed during the preparation of license renewal applications. Therefore, applicants for license renewal will be responsible for developing and describing the plant-specific AMPs and addressing each of the ten elements specified in the Draft Standard Review Plan.	Aging management programs credited for managing effects of aging for concrete and steel Containment components and the post-tensioning sub-system contain the ten (10) elements identified in the SRP. These programs are described in Appendix B of the LRA. • Water Chemistry Control Program • Boric Acid Corrosion Program· • Structures Monitoring Program • Periodic Surveillance and Preventive Maintenance Program • ASME Section XI, Subsections IWE & IWL Inservice Inspection ProgramI

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(21) The WOG GTR indicates that the license renewal applicant may update an existing design fatigue analysis to account for the additional years of plant operation or manage the effects of the aging mechanism through aging management programs. The GTR uses AMP 5.5 for managing the effects of fatigue during the renewal license period, and basically endorses the ASME Code Section XI surveillance and testing program. For components where CLB fatigue TLAAs exist, this option would allow the CLB fatigue Section III cumulative usage factors (CUF) to be exceeded during the period of extended operation. The staff has not endorsed this option on a generic basis at this time. An applicant wishing to pursue this option would have to obtain staff review and approval on a case-by-case basis. For components where CLB fatigue TLAAs do not exist (are not addressed in 10 CFR 54.21), aging effects due to fatigue can be addressed by either a Section III fatigue analysis (including the additional years for the period of extended operation) or by adequately managing these effects for the period of extended operation.	Concrete Components Fatigue is the progressive degradation of materials subjected to application of cyclic loads that are less than the maximum allowable static loads. Concrete components at the PBNP were designed in accordance with ACI 318 and therefore have excellent low-cycle fatigue properties. ACI standards limit the maximum design stress to less than 50% of the static stress of the concrete. The concrete fatigue strength is about 55% of its static strength at extremely high cycles ($>10^7$ cycles) of loading. Therefore, fatigue is not an aging mechanism that can lead to cracking for Containment structure concrete components at PBNP. Steel Components For steel components, fatigue is the cumulative effect of microstructural localized plastic deformation in the material section that occurs with each cycle of applied stress of sufficient magnitude. The containment metal liner was designed in accordance with the ASME III, Class B, 1965 Edition. The effects of fatigue was considered by the code. This issue is further discussed in Applicant Action Item 23. Cracking due to metal fatigue is treated as a Time-Limited Aging Analysis (TLAA) at PBNP if the component is included in the current licensing basis (CLB).
(22) Specify the containment structure components and provide plant-specific details of the TLAAs for prediction of cumulative fatigue usage through the period of extended operation.	There are no TLAAs for prediction of cumulative fatigue usage of Containment structure components at PBNP.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(23) Specify those containment structure components for which fatigue is an applicable aging mechanism, but no CLB fatigue analysis based on a 40-year plant life exists. In addition to implementation of AMP 5.5, the requirements of 10 CFR 50.55a should be met.	Containment Liner and Penetrations The Containment liner, liner penetrations, and liner steel components were originally designed to comply with ASME Boiler and Pressure Vessel Code, Section III-1965 for pressure boundary and the AISC Code for structural steel. Implementation of the ASME design criteria requires that the liner material be prevented from experiencing significant distortion due to thermal loads and that the stresses be considered from a fatigue standpoint. The liner plate at PBNP is restrained against significant distortion by continuous angle anchors and the temperature limitation of 700°F is never exceeded. The requirement of limiting strains on the basis of fatigue considerations is also satisfied. Further, the anchors are designed to preclude failure when subjected to the worst possible load combinations. In summary, the following fatigue loads were considered in the design: thermal cycling due to annual outdoor temperature variations, thermal cycling due to reactor system startup and shutdown, and thermal cycling due to the design basis accident. Consequently, the liner plate is acceptable for the period of extended operation. (Reference Section 4.3.11) Tendon Wire Fatigue Analysis Fatigue tests were conducted by the Swiss Federal Testing Station (EMPA) in 1960 on individual 7-mm tendon wires and on 18-wire tendons. The tendons and wires were cycled between 0.7 UTS and 0.8 UTS (ultimate tensile strength) for over 2 million cycles without the failure of a single wire. This original seismic fatigue evaluation for the tendon wires remains valid throughout the period of extended operation. The imposed containment tendon pre-loads (prestress) are larger than the service cycling

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(23) (continued)	loads. Therefore, the tendons are not subjected to fatigue loadings. However, prestress of the containment tendons decreases over time. The magnitude of prestress losses, at the time of initial licensing, was predicted and the estimated final effective preload was calculated for each tendon type. New limit curves and prestressing force trend lines were established for all tendons. The predicted final preload at the end of the extended operation period, for all tendons, exceeds the minimum required preload. Consequently, the post-tensioning sub-system will continue to perform its intended function throughout the period of extended operation. Nevertheless, the programs that manage containment structure components, are as follows: the Structures Monitoring Program, and the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program.
(24) For prestressed concrete containments, provide plant-specific details of the TLAA for prediction of tendon prestress losses through the period of extended operation.	In accordance with ACI 318-63 and the PBNP FSAR, the design of the Containment Structure post-tensioning sub-system accounts for prestress losses caused by the following mechanisms or processes: • Elastic shortening of concrete· • Creep of concrete· • Shrinkage of concrete· • Stress-relaxation in steel tendon wires· • Frictional loss due to curvature in the tendons and contact with tendon conduits. No allowance is made for seating of the BBRV anchor since no slippage occurs in the anchor during transfer of the tendon load to the structure. The confirmatory program that monitors tendon prestress issues is the Pre-Stressed Concrete Containment Tendon Surveillance Program.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(25) The GTR identified structural connections as containment structure components that require aging management in Table 2-1. However, there is no definition or description of structural connections in GTR Section 2.0. A definition and a description of the AMP for structural connections are needed.	There are no Containment structural connections unique to PBNP. The parts or subcomponents that could be considered structural connections in GTR Table 2-1 are addressed under the tendon post tensioning sub-system, shell and dome, penetrations, equipment and personnel hatches. Therefore, a description of the AMP for structural connections need not be provided. Note that the Structures Monitoring Program, and the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program manage aging effects.
(26) The GTR identified embedments as containment structure components that require aging management in Table 2-1. However, there is no definition or description of embedments in GTR Section 2. A definition and a description of the AMP for embedments are needed.	Embedments are those steel subcomponents that extend into and are encased within the concrete. Steel embedments are associated with the components given in GTR Table 2-1 (e.g., steel liner and its penetrations). Additional steel embedments are associated with miscellaneous equipment attached to the containment structure. LRA Table 3.5.2-1 column, Component Type, identifies equipment, some of which would have embedments. Corrosion is insignificant for reinforced concrete components constructed in accordance with design codes that limit excessive cracking, thereby protecting the reinforcement/embedments against infiltration of aggressive environments. In addition, the environments at PBNP are non-aggressive. Corrosion of concrete embedded steel is precluded, therefore it has no aging mechanism requiring management.

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(27) The GTR does not commit to inspection of inaccessible areas when there is no indication of degradation of adjacent accessible areas, except when the potential for degradation is “event driven”; i.e., some unusual event has occurred which has the potential to degrade inaccessible areas of the containment structures. Therefore, the GTR cannot be referenced by license renewal applicants for managing aging of inaccessible areas. Individual license renewal applicants are required to describe a program for inspection of inaccessible areas or adopt a program endorsed by the staff in similar applications.	Structural components inaccessible for inspection are managed by inspecting accessible structures with similar materials and environments for aging effects that may be indicative of age-related degradation of inaccessible structural components. The programs credited for managing aging effects of inaccessible structural components are the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program as augmented by 10 CFR 50.55a (b)(2)(ix)(A) and explained in SECY-96-080. In addition, PBNP has implemented augmented examinations to inspect the inaccessible containment floor liner plate. Concrete core drilled access holes were installed inside the containment to monitor the liner plates corrosion rate. Little corrosion has been observed to date. This is fully discussed and addressed in Table 3.5.1 Line Number 12 and Section 3.5.2.2.1.4 of the LRA. The above noted programs will be continued into the extended period of operation as defined by the license renewal program. Therefore, the programs used at PBNP, to inspect inaccessible areas, follows the program endorsed by the staff in NUREG-1801 and the amendment to 10 CFR 50.55a (SECY-96-080).

Table 3.5.0-1 Containment Structure - WCAP-14756-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(28) The aging effects in concrete due to leaching of calcium hydroxide and alkali aggregate reaction are identified in the GTR as not requiring aging management. This is unacceptable because plant-specific evaluation of their applicability is needed. Therefore, if these aging mechanisms (leaching of calcium hydroxide and alkali aggregate reaction) are applicable, applicants would be required to propose a plant specific aging management program. Alternatively, applicant can credit the ASME Code, Section XI, Examination Category L-A as an adequate aging management program.	A detailed response for the postulated aging effects of concrete do to leaching of calcium hydroxide and alkali aggregate reaction is presented in the response to Applicant Action Item Number 8. In summary, degradation caused by leaching of calcium hydroxide is not an applicable aging mechanism for the PBNP Containment structure. Further, alkali aggregate reaction is not an applicable aging mechanism for the PBNP Containment.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(1) Definition of “local” and “adjacent” (Section 3.1) The Westinghouse Owners Group did not clearly define the term “local” in its report. However, the aging management programs could be the same for all concrete structures and structural components, therefore, the license renewal applicants must describe the aging management program for adjacent concrete structures and any differences from the aging management program for the local concrete structures.	Concrete local to baseplates or embedments are addressed in the Class 1 RCS Supports aging management review. It includes concrete loaded directly by the equipment, i.e., support baseplate and its anchors or embedments. Concrete adjacent to the support is addressed in the Containment Structure and Containment Structural Components aging management review. The programs that manage “adjacent” and “local” concrete include the Structures Monitoring Program and the ASME Section XI, Subsection IWF Inservice Inspection Program.
(2) Detailed description of the Reactor Coolant System supports (Section 3.1) A license renewal applicant will have to justify any differences between its Reactor Coolant System support system and the figures and descriptions of the supports systems contained in the Westinghouse Owners Group report.	The configurations of the RCS component supports at PBNP are identical to those described in the GTR, namely: • Reactor Vessel Supports - Configuration 2 • Steam Generator Supports - Configuration 3 • Reactor Coolant Pump Supports - Configuration 2 • Pressurizer Supports - Configuration 2 • RCS Pressurizer Surge Line Support - Variable spring hangers
(3) Discrepancies and Omissions (Section 3.1) The Westinghouse Owners Group report contains many discrepancies and omissions. A license renewal applicant needs to resolve these discrepancies and omissions in its application. 1. Wear plates and bearing pads are included as support components and are within the scope of this Westinghouse Owners Group report but are not identified in Table 2-1 as parts and sub-components requiring an aging management review.	1. GTR Table 2-1 of Section 2 includes wear plates and bearing pads.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
2. Sketches of Reactor Coolant Pump support configuration 4 and Pressurizer support configuration 2 are not provided in the Westinghouse Owners Group report.	2. The PBNP RCP supports are represented by Configuration 2, not Configuration 4. Figure 2-9 in the GTR depicts RCP supports, Configuration 2. Pressurizer supports are represented by the configuration of Figure 2-11. By eliminating the upper supports portion of the figure, it can be seen that the pressurizer is bolted into the concrete floor anchors and that it is a bottom-skirt supported vessel.
3. Section 3.2.9 of the Westinghouse Owners Group report indicates that ASTM A36 steel is used in Steam Generator and Reactor Coolant Pump supports, however, ASTM A36 steel is not included in the list of material for the primary component supports (Table 2-4).	3. ASTM A36 “Standard Specification for Structural Steel” and ASTM A53 “Specifications for Welded and Seamless Steel Pipe” are included in the scope of the PBNP aging management review as they are utilized in RCS supports.
4. The 1963 AISC manual (Ref. 3) states that the following steel materials are commonly used for steel construction but they are not listed in Table 2-4 of the Westinghouse Owners Group report. They are ASTM A7, A36, A242, A373, A440, and A441 structural steel and ASTM A325 bolts.	4. Of the materials listed from Reference 3 ASTM A36 and A325 are used in the PBNP RCS supports. These materials have been included in the scope of the PBNP aging management review.
5. There are no specific descriptions and sketches for the pressurizer surge line supports.	5. A description of the PBNP pressurizer surge line supports has been included in the aging management review report. There are three supports (variable spring hangers), RC-1 through RC-3, for each unit. They are the only supports for each line.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(4) Strain Aging Embrittlement (Section 3.3.1.4) Temper embrittlement and strain aging embrittlement are the most common forms of thermal embrittlement that are seen in ferritic materials as stated in Section 3.2.4 of the Westinghouse Owners Group report. The Westinghouse Owners Group report has determined that temper embrittlement is not a concern for the ferritic materials of Reactor Coolant System supports. However, the Westinghouse Owners Group report does not address the aging effects from strain aging embrittlement but states that thermal embrittlement is not applicable. The license renewal applicants will address the applicability of the aging effects due to strain energy embrittlement to their plants.	RCS supports at PBNP: a. do not contain cast austenitic stainless or low carbon steels; b. are not loaded beyond the elastic limit during normal operation, and c. operate at temperatures below 450°F. Therefore, thermal and strain-aging embrittlement are not applicable aging mechanisms at PBNP. No aging management of age-related degradation caused by these mechanisms is required.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(5) Low Fracture Toughness (Section 3.3.1.6) Appendix C of NUREG-0577 addresses this item and groups many Westinghouse Owners Group member plants as Group I “plants requiring further evaluation.” Although Table B9 of NUREG-1557 indicated that “low fracture toughness is not significant for containment internal structures,” in general, these two documents only addressed the containment internal structures as a whole and did not specifically address the Reactor Coolant System support components. Westinghouse Owners Group recognizes this concern and states in Section 3.2.9 of its report that “Utilities with potential problems were required to demonstrate that the suspect structures have adequate fracture toughness to comply with the criteria defined in NUREG-0577.” However, it further states that “low fracture toughness does not cause detrimental aging effects that must be addressed by maintenance programs.” The staff does not believe that the Westinghouse Owners Group report provides sufficient information to support this conclusion. A license renewal applicant will address, if its plant is listed as Group 1 in Appendix C of NUREG-0577, that its plant had performed an analysis and the steel components of its RCS supports have adequate fracture toughness that no maintenance program is necessary.	Plant-specific evaluation of low fracture toughness and lamellar tearing as applicable to the PBNP RCS supports was performed and submitted to the NRC in 1980. The primary conclusion of this analysis was that low fracture toughness and lamellar tearing are not a concern for the design and installation of the RCS supports at PBNP. PBNP was listed in Appendix C of NUREG-0577, Rev 1 as being in “Group 1,” a plant whose SG and RCP supports required further evaluation. Apparently, this classification of PBNP was because the main support columns are fabricated from A53 pipe and the steel pipe was characterized by NUREG-0577 as a material with very loose specifications. However, the purchase order invoked the ASTM A53 specification supplemental requirement that each length of pipe be hydrostatic tested to a prescribed pressure (a minimum of 2400 psi for 12-inch, schedule 100 pipe). ASTM A53 supplemental requirements also required that piping not classified as double extra strong be subjected to a cold flattening test, as an evaluation of the material's ductility. Furthermore, NUREG-0577 acknowledged that section sizes under one inch have a relatively low susceptibility to brittle failure. Note that the 12-inch diameter, schedule 100, pipe has a wall thickness of 0.843 inches. Therefore, no aging management program is required for the RCS supports due to the effects of low fracture toughness and lamellar tearing during the extended period of operation.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(6) Fatigue (Section 3.3.1.7) A license renewal applicant will have to justify any differences between the materials used for its Reactor Coolant System supports and the values listed in Table 2-4 of the Westinghouse Owners Group report.	The difference between materials used for the PBNP RCS supports and those shown in Table 2-4 of the GTR is that ASTM A36, A53, A322, and A325 carbon steel is used in the Reactor Coolant System supports. However, none of these materials are used in a design configuration where the loading is cyclic and, therefore, fatigue is not a concern.
(7) Irradiation of Concrete (Section 3.3.2.3) The Westinghouse Owners Group report states that concrete degradation from irradiation will be addressed by plant-specific evaluation. The staff agrees with this suggestion and the license renewal applicant must develop plant-specific program(s) to evaluate this concern.	Irradiation degradation thresholds for concrete where cumulative neutron fluence does not exceed 10^{19} n/cm^2 (fast and slow neutrons) and 10^{10} rads (gamma), is not a significant age related degradation mechanism. For PBNP the worst case, 60-year cumulative neutron fluence level applicable to concrete, is 7.5×10^{18} n/cm^2. The worst case, 60-year cumulative, concrete gamma dose level at PBNP is 3×10^7 rads. The cumulative radiation fluence and dose levels (neutron and gamma) received by the PBNP concrete is well below the degradation threshold limits. Therefore, irradiation is not an applicable aging mechanism for the structural concrete at PBNP.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(8) Elevated Temperature of Concrete (Section 3.2.4) The Westinghouse Owners Group report states that concrete operating temperature should not exceed 150°F and local area temperature should be kept under 200°F. The Westinghouse Owners Group report further states that reactor pressure vessel supports could be subjected to high temperatures that could potentially result in a local temperature above 200°F if supplemental cooling is not provided. For those support configurations where the local temperature at concrete surfaces could exceed 200°F, special design features are incorporated based on air or water cooling to keep local temperature below 200°F. These temperatures are specified in the ASME Code. Therefore, elevated temperature is not a concern for concrete. Because the operating temperature of concrete components are kept below the limits specified by the code by means of supplemented cooling, the staff considers that the aging effects of elevated temperature are applicable to the Reactor Coolant System supports and are being managed by supplemented cooling features. The license renewal applicants will address the concern that the aging effects associated with elevated temperature are applicable and demonstrate that the existing design features in the plants are capable of preventing any unacceptable degradation during the period of extended operation.	Cracking due to elevated temperature is not an aging effect requiring management at PBNP since concrete temperatures are maintained below American Concrete Institute (ACI) code thresholds due to normal containment and supplemental cooling. Cooling systems that limit long term concrete temperatures to less than 150°F include the Containment Air Recirculation System and the Reactor Cavity Cooling System. The air temperature entering the reactor compartment is monitored to assure compliance with these design requirements.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(9) SRP-LR (Section 3.4) The attributes of the aging management programs provided in the Westinghouse Owners Group report do not address all elements as listed in Table A1-1 of Appendix A of the SRP-LR. The applicants should address the missing review elements and describe the plant-specific experience, if any, related to aging degradation of the Reactor Coolant System supports in their applications.	The aging management program descriptions contained in Appendix B of the License Renewal Application (LRA) address all required elements. The program descriptions also contain relevant PBNP-specific operating experience.
(10) Details of leakage walk-downs and leakage monitoring program (Section 3.4.2) A license renewal applicant must provide the necessary details to perform leakage identification walkdowns and the details of the leakage monitoring program(s), especially the frequencies, for Aging Management Program 1-1 and Aging Management Program 1-2.	The PBNP Boric Acid Corrosion Program manages aging effects for structures and components as a result of borated water leakage. The program requires periodic visual inspection of all systems that contain borated water for evidence of leakage or accumulations of dried boric acid crystals. A description of the Boric Acid Corrosion Program is contained in Appendix B of the LRA.
(11) Baseline Inspection (Section 3.4.2) All structures and structural components need a baseline inspection to document the condition of the structures and structural components. Therefore, the renewal applicants must have plant-specific baseline inspection results for all structures and structural components, or a planned inspection to obtain such results and validate the aging management programs prior to entering the period of extended operation.	Although not characterized as “baseline inspections” at the time they were performed, inspections that serve as baseline inspections have been performed and documented for the RCS Supports under the PBNP ASME Section XI, Subsection IWF Inservice Inspection Program.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(12) Inspection of inaccessible areas (Section 3.4.2) For RCS supports located in inaccessible areas, a license renewal applicant must provide an inspection program to inspect these RCS supports or provide technical justification for not performing inspection.	Structural components inaccessible for inspection are managed by inspecting accessible structures with similar materials and environments for aging effects. These aging effects would be indicative of age-related degradation of inaccessible structural components. If aging effects are observed for the accessible structures, then a detailed review and assessment will be performed for the inaccessible components. Issues to resolve will include the aging impact on the component and follow up and/or corrective actions to be taken. The programs credited for managing aging effects of inaccessible structural components are the ASME Section XI, Subsection IWF Inservice Inspection Program and the Boric Acid Corrosion Program. These programs are described in Appendix B of the LRA.
(13) Surveillance Frequency for AMP-1.2 (Section 3.4.3) AMP-1.2 specifies inspection frequency in accordance with the requirements of Subsection IWF-2410 (Inspection Program) and Table IWB-2412-1, each 10-year interval following the first interval, 10-year inspection program, with IWB-2412. The staff considers the frequency proposed by Westinghouse Owners Group not to be adequate. The proposed frequency is in accordance with ASME standards, but the inspections are to the requirements of ACI Standards, therefore, the frequency of inspection should also follow the recommendations of the ACI standards. Inspection frequencies recommended by ACI 349.3R-96 are every 10 years for below grade structures and controlled interiors and every 5 years for all other structures. Section 4.2.4.1 of NUREG/CR-6424 has the same recommendation for inspection frequencies. A license renewal applicant must address this concern in its application.	For PBNP, two aging management programs were identified for concrete embedments. The Boric Acid Corrosion Program is credited for managing degradation from boric acid leaks and the Structures Monitoring Program for managing general loss of material and change in material properties. Both aging management programs, described in Appendix B, meet or exceed the frequencies recommended in ACI 349.3R.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
(14) Acceptance criteria for leakage walkdowns (Section 3.4.4) In accordance with the Westinghouse Owners Group report, leakage walkdowns and monitoring are plant-specific. Therefore, a license renewal applicant will have to provide the necessary qualitative or quantitative acceptance criteria for leakage walkdowns and monitoring.	Acceptance criteria for leakage walkdowns and monitoring are included in the PBNP Boric Acid Corrosion Program, which is described in Appendix B of the LRA.
(15) Acceptance Criteria for AMP-1.2 (Section 3.4.4) AMP-1.2 specifies acceptance criteria in accordance with several ACI standards. These ACI standards are ACI 201.2R-77, ACI224.1R-89, and ACI 224R-89. The staff has reviewed these ACI standards and concluded that, except for ACI 224.1R, they are mainly for design and construction rather than aging effects management because those concrete properties are built-in by design and construction. However, they do contain attributes that can be used to develop inspection acceptance criteria for AMP-1.2. For leakage walkdowns and leakage monitoring, the acceptance criteria are the same as that listed for AMP-1.1. The staff has also reviewed ACI 349.3R-96, which is referenced in the Westinghouse Owners Group report for surveillance technique, and concluded it has acceptance criteria that can be modified and used as the inspection acceptance criteria for AMP-1.2. These criteria include acceptance without further evaluation, acceptance after review, and conditions requiring further evaluation. The license renewal applicants will provide a description of the inspection acceptance criteria in their application for the staff to review.	The inspection criteria for the aging management program to control effects of aggressive chemical attack and corrosion of concrete embedments at PBNP are described in the Structures Monitoring Program. These criteria are based in part on ACI 349.3R-96. Acceptance criteria contained in ACI 349.3R-96 that can be used as inspection acceptance criteria for the concrete embedment area associated with RCS supports is incorporated into the Structures Monitoring Program's implementing procedures. This program is described in Appendix B of the LRA.
(16) Plant-Specific Programs. Recommendations from Section 5 of the Westinghouse Owners Group report (Section 3.6)	Responses to specific items are arranged in the same order as in the preceding column.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
• Identification and evaluation of any plant-specific Time-Limited Aging Analyses applicable to their Reactor Coolant System supports.	• Fatigue is the only TLAA associated with the RCS supports. A discussion of TLAAs is presented in Section 4.0 of the LRA. No explicit fatigue evaluation was performed during the design of RCS supports for the PBNP. In addition, the RCS supports are not subjected to continuous cycling loads. Review of the CLB and other analyses related to RCS supports did not identify any other TLAA.
• Identification and evaluation of current-term programs implemented within the current licensing term to address technical issues from industry practices and United States Nuclear Regulatory Commission (NRC) directives [that] should be continued into the license renewal term. Modifications to or elimination of these programs have to be justified.	• Current-term programs implemented within the current licensing term at the PBNP to address technical issues that were identified from industry practices and NRC directives will be continued into the license renewal term, without modifications.
• Identification and justification of plant-specific programs that deviate from the recommended aging management programs.	• Plant-specific programs for aging management of the PBNP RCS supports do not deviate from those recommended by the GTR such that the effectiveness of the program is reduced. A detailed program comparison with NUREG-1801, April 2001, has been conducted and results are presented in Appendix B of the LRA.
• Identification of any specific program necessary to ensure that proper preload is retained for the component supports within the scope of this report.	• Loss of preload for bolted joint connections is not an aging effect requiring management for the RCS supports at the PBNP. The supports design did not include the requirement for preload.
• Identification of any evidence of aging degradation in inaccessible areas during the current licensing term, that is considered to potentially affect system intended functions. A plan of action to address any identified potential degradation should be provided.	• The PBNP Structures Monitoring Program covers the identification of aging degradation in inaccessible areas during the current and for the extended licensing term. A plan of action to resolve or address identified problems is also provided.

Table 3.5.0-2 Reactor Coolant System Supports - WCAP-14422, Rev. 2-A, Final Safety Evaluation Report Response to Applicant Action Items

Renewal Applicant Action Item	Plant-Specific Response
• Verification that the plant is bounded by this GTR. The actions applicants must take to verify that this plant is bounded will be provided in an implementation procedure.	• Based on review of the installed configuration, operating environment, and materials of construction of the RCS supports, PBNP is bounded by the Reactor Coolant System Supports GTR. Plant-specific data are given in this report, show that indeed this is true.
• Plant-specific evaluation of potential degradation due to irradiation of the components within the scope of this report.	• Potential degradation due to irradiation of the RCS supports components within the scope of License Renewal is very low. Consequently, no specific aging management activity is needed.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
Common Components of All Types of PWR and BWR Containment					
3.5.1-01	Penetration sleeves, penetration bellows, and dissimilar metal welds	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA (see [SRP] subsection 3.5.2.2.1.6)	Further evaluation documented in Section 3.5.2.2.1.6.
3.5.1-02	Penetration sleeves, bellows, and dissimilar metal welds.	Cracking due to cyclic loading, or crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	Yes, detection of aging effects is to be evaluated (see [SRP] subsection 3.5.2.2.1.7)	Further evaluation documented in Section 3.5.2.2.1.7.
3.5.1-03	Penetration sleeves, penetration bellows, and dissimilar metal welds	Loss of material due to corrosion	Containment ISI and Containment leak rate test	No	The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program ensures that the containment ISI and leak rate tests adopt and implement the requirements of ASME Section XI, Subsections IWE & IWL and 10 CFR 50 Appendix J. Included in the scope of the IWE program are the exposed portions of the containment liner, the fuel transfer penetration, all other penetrations, associated bolting, moisture barriers, and all airlocks, seals, gaskets and penetration bellows (if Type B tested by Appendix J). Inspections and leak rate tests performed in accordance with the containment inspection procedures verify the containment pressure boundary integrity and may be credited for detecting loss of material due to corrosion.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-04	Personnel airlock and equipment hatch	Loss of material due to corrosion	Containment ISI and Containment leak rate test	No	The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program ensures that the containment ISI and leak rate tests adopt and implement the requirements of ASME Section XI, Subsections IWE & IWL and 10 CFR 50 Appendix J. Included in the scope of the IWE program are the exposed portions of the containment liner, the fuel transfer penetration, all other penetrations, associated bolting, moisture barriers, and all airlocks, seals, gaskets and penetration bellows (if Type B tested by Appendix J). This program may be credited for managing the aging effects of loss of material due to corrosion.
3.5.1-05	Personnel airlock and equipment hatch	Loss of leak tightness in closed position due to mechanical wear of locks, hinges and closure mechanism	Containment leak rate test and Plant Technical Specifications	No	The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program ensures that the containment ISI and leak rate tests adopt and implement the requirements of ASME Section XI, Subsections IWE & IWL and 10 CFR 50 Appendix J. Included in the scope of the IWE program are the personnel and emergency airlocks, and the equipment hatch. The containment leak rate tests are performed in accordance with the requirements of 10 CFR 50 Appendix J. The IWE program performs visual inspections of hatches, hinges, locks, and closure mechanisms associated with the containment air locks and equipment hatch. The program may be credited with managing the aging effects of loss of leak tightness in the closed position due to mechanical wear of locks, hinges and closure mechanisms.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-06	Seals, gaskets, and moisture barriers	Loss of sealant and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers	Containment ISI and Containment leak rate test	No	The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program ensures that the containment ISI and leak rate tests adopt and implement the requirements of ASME Section XI, Subsections IWE & IWL and 10 CFR 50 Appendix J. Included in the scope of the IWE program are the visual inspections of elastomeric seals associated with the containment air locks and electrical penetrations. The program may be credited with managing the aging effects of loss of sealant and leakage through containment due to deterioration of gaskets.
PWR Concrete (Reinforced and Prestressed) and Steel Containment BWR Concrete (Mark II and III) and Steel (Mark I, II, and III) Containment					
3.5.1-07	Concrete elements: foundation, walls, dome.	Aging of accessible and inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment ISI	Yes, if aging mechanism is significant for inaccessible areas (see [SRP] subsection 3.5.2.2.1.1)	Further evaluation documented in Section 3.5.2.2.1.1.
3.5.1-08	Concrete elements: foundation	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	No, if within the scope of the applicant's structures monitoring program (see [SRP] subsection 3.5.2.2.1.2)	Further evaluation documented in Section 3.5.2.2.1.2.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-09	Concrete elements: foundation	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	No, if within the scope of the applicant's structures monitoring program (see [SRP] subsection 3.5.2.2.1.2)	Further evaluation documented in Section 3.5.2.2.1.2.
3.5.1-10	Concrete elements: foundation, dome, and wall	Reduction of strength and modulus due to elevated temperature	Plant specific	Yes, for any portions of concrete containment that exceed specified temperature limits (see [SRP] subsection 3.5.2.2.1.3)	Further evaluation documented in Section 3.5.2.2.1.3.
3.5.1-11	Prestressed containment: tendons and anchorage components	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA (see [SRP] subsection 3.5.2.2.1.5)	Further evaluation documented in Section 3.5.2.2.1.5.
3.5.1-12	Steel elements: liner plate, containment shell	Loss of material due to corrosion in accessible and inaccessible areas	Containment ISI and Containment leak rate test	Yes, if corrosion is significant for inaccessible areas (see [SRP] subsection 3.5.2.2.1.4)	Further evaluation documented in Section 3.5.2.2.1.4.
3.5.1-13	BWR only				

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-14	Steel elements: protected by coating	Loss of material due to corrosion in accessible areas only	Protective coating monitoring and maintenance	No	Protective coatings are not credited with managing the effects of aging at Point Beach. PBNP recognizes the benefits derived from protective coatings. However coatings, in and of themselves, do not perform License Renewal intended functions. That notwithstanding, steel elements in containment are inspected for corrosion by both the Structures Monitoring Program and the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program. When a steel coating is found degraded it is evaluated and repaired in accordance with station procedures.
3.5.1-15	Prestressed containment: tendons and anchorage components	Loss of material due to corrosion of prestressing tendons and anchorage components	Containment ISI	No	The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program ensures that the containment ISI and leak rate tests adopt and implement the requirements of ASME Section XI, Subsections IWE & IWL and 10 CFR 50 Appendix J. Included in the scope of the IWL program are the post-tensioning tendons and hardware of the concrete containment. Inspections and tests include periodic liftoff tests, grease analysis, and visual inspection of the tendon anchorage hardware which ensures the equipment is not exposed to moisture. This program provides reasonable assurance that loss of material due to corrosion will be effectively managed This program may be credited for managing the aging effects of loss of material due to corrosion of prestressing tendons and anchorage components.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-16	Concrete elements: foundation, dome, and wall	Scaling, cracking, and spalling due to freeze-thaw; expansion and cracking due to reaction with aggregate	Containment ISI	No	The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program identifies that an aging mechanism is present and active and also provides confirmation and verification of the absence of all types of aging effects. Aging effects may be absent if the materials of construction, design specifications, and operational environment preclude an aging mechanism but, it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is applicable. Containment concrete elements have been evaluated for the following aging mechanisms: Aging Mechanism: Freeze-Thaw Aging Effect: Loss of Material Evaluation: The contract-specified air contents are within the range specified by ACI 318-63, and the contract-specified water-to-cement ratio meets the recommendations of ACI 318-63. Therefore, loss of material and cracking of concrete due to freeze-thaw are not probable aging effects at Point Beach and have not been observed to date. Aging Mechanism: Reaction with Aggregates Aging Effect: Cracking, Expansion Evaluation: During construction the aggregates were tested for potential reactivity in accordance with ASTM C227 and ASTM C295, cracking and expansion due to reaction with aggregates are not probable aging effects at Point Beach and have not been observed to date.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-16 (con't)					Operating experience has shown that concrete has not experienced unanticipated aging effects at Point Beach. That notwithstanding, the identification of the above aging effects by the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program, as well as the resistance provided by the materials of construction provide adequate assurance that all types of concrete aging effects will be identified and managed through out the extended period of operation.
3.5.1-17	BWR only				
3.5.1-18	BWR only				
3.5.1-19	BWR only				
Class 1 Structures					
3.5.1-20	All Groups except Group 6: accessible interior/exterior concrete & steel components	All types of aging effects	Structures Monitoring	No, if within the scope of the applicant's structures monitoring program (see [SRP] subsection 3.5.2.2.2.1)	Further evaluation documented in Section 3.5.2.2.2.1.
3.5.1-21	Groups 1-3, 5, 7-9: inaccessible concrete components, such as exterior walls below grade and foundation	Aging of inaccessible concrete areas due to aggressive chemical attack, and corrosion of embedded steel	Plant-specific	Yes, if an aggressive below-grade environment exists (see [SRP] subsection 3.5.2.2.2.2)	Further evaluation documented in Section 3.5.2.2.2.2.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-22	Group 6: all accessible/ inaccessible concrete, steel, and earthen components	All types of aging effects, including loss of material due to abrasion, cavitation, and corrosion	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance	No	Water-Control Structures and earthen embankments inspections are incorporated into the Structures Monitoring Program. Included is the earthen berm around the Fuel Oil Storage Tank and the Circulating Water Pump House and its forebays, pumpbays, and discharge seal well. The Structures Monitoring Program effectively manages all types of aging effects for earth, concrete and steel, including loss of material due to abrasion, cavitation, erosion and corrosion. It identifies that an aging mechanism is present and active and also provides confirmation and verification of the absence of all types of aging effects. Aging effects may be absent if the materials of construction, design specifications, and operational environment preclude an aging mechanism but, it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is present. Concrete exposed to flowing water has been evaluated for the following aging mechanisms: Aging Mechanism: Abrasion, Cavitation Aging Effect: Loss of Material Evaluation: Flow velocities at the forebays, pumpbays, and discharge seal wells are less than the values at which cavitation occur. Abrasion has been observed at the discharge seal wells due in part to an abrupt change in flow direction and sediment laden water. Under water inspections are performed as a repetitive task as part of the Structures Monitoring Program.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-22 (con't)					Point Beach does not utilize Reg. Guide 1.127, "Inspections of Water-Control Structures Associated with Nuclear Power Plants" or have programs under the regulatory jurisdiction of FERC or the Army Corp of Engineers. The water control structure inspections are performed in accordance with the Structures Monitoring Program. It satisfies all the appropriate criteria and provides assurance that the intended functions of the water control structure will be maintained through the period of extended operation. Although the components and aging effects monitored are consistent, the program differs with NUREG-1801.
3.5.1-23	Group 5: liners	Crack initiation and growth from SCC and loss of material due to crevice corrosion	Water Chemistry Program and Monitoring of spent fuel pool water level	No	The Water Chemistry Control Program is credited with managing the aging effects of crack initiation and growth from SSC and loss of material due to crevice corrosion for the spent fuel pool liner and refueling transfer canal liner. Plant Technical Specification 3.7.10, Fuel Storage Pool Water Level, as well as plant operating procedures provide monitoring and control of the spent fuel pool water level. In addition, spent fuel pool leak off is monitored per plant operating procedures.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-24	Groups 1-3, 5, 6: all masonry block walls	Cracking due to restraint, shrinkage, creep, and aggressive environment	Masonry Wall	No	Masonry wall inspections are incorporated into the Structures Monitoring Program. The Structures Monitoring Program effectively manages cracking due to restraint, shrinkage and creep. Concrete degradation due to aggressive environment is insignificant due to Point Beach environments being non-aggressive. The Structures Monitoring Program monitors for indications of cracking due to restraint, shrinkage and creep on masonry walls.
3.5.1-25	Groups 1-3, 5, 7-9: foundation	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	No, if within the scope of the applicant's structures monitoring program (see [SRP] subsection 3.5.2.2.1.2)	Further evaluation documented in Section 3.5.2.2.1.2.
3.5.1-26	Groups 1-3, 5-9: foundation	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	No, if within the scope of the applicant's structures monitoring program (see [SRP] subsection 3.5.2.2.1.2)	Further evaluation documented in Section 3.5.2.2.1.2.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-27	Groups 1-5: concrete	Reduction of strength and modulus due to elevated temperature	Plant-specific	Yes, for any portions of concrete that exceed specified temperature limits (see [SRP] subsection 3.5.2.2.1.3)	Further evaluation documented in Section 3.5.2.2.1.3.
3.5.1-28	Groups 7, 8: liners	Crack Initiation and growth due to SCC; Loss of material due to crevice corrosion	Plant-specific	Yes	All tanks within the scope of License Renewal receive their aging management evaluation with the system they serve. Thus, this line item is not applicable to class 1 structures at Point Beach.
Component Supports					
3.5.1-29	All Groups: support members: anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc.	Aging of component supports	Structures Monitoring	No, if within the scope of the applicant's structures monitoring program (see [SRP] subsection 3.5.2.2.3.1)	Further evaluation documented in Section 3.5.2.2.3.1.
3.5.1-30	Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA (see [SRP] subsection 3.5.2.2.3.2)	Further evaluation documented in Section 3.5.2.2.3.2.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-31	All Groups: support members: anchor bolts, welds	Loss of material due to boric acid corrosion	Boric acid corrosion	No	Consistent with NUREG-1801. The Boric Acid Corrosion Program monitors for loss of material due to boric acid corrosion in all plant areas that contain systems that use boric acid. In addition to support members, the program also monitors and evaluates structural members, fasteners and welds that could be potentially exposed to borated water leaks.
3.5.1-32	Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds, spring hangers, guides, stops, and vibration isolators	Loss of material due to environmental corrosion; loss of mechanical function due to corrosion, distortion, dirt, overload, etc.	ISI	No	The ASME Section XI, Subsection IWF Inservice Inspection Program monitors all elements of safety related supports for degradation. Visual examinations inspect for corrosion, deformation, misalignment, improper clearances, and missing detached, or loose support items. Additionally, some non-ASME supports sub-components (baseplates, grout and expansion anchors) are included in the scope of the Structures Monitoring Program but get inspected at the same time of the ISI-IWF inspections.
3.5.1-33	Group B1.1: high strength low-alloy bolts	Crack initiation and growth due to SCC	Bolting integrity	No	The Bolting Integrity Program includes the use of ISI to evaluate and monitor crack initiation and growth due to SSC, if present, in high strength low-alloy steel bolts used in NSSS component supports.

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Basemat	Direct Flow Pressure Boundary Shelter SR Support NSR Support SR	Concrete (Reinforced)	Buried (External)	None	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program			26
					Structures Monitoring Program			26
Concrete/Indoor - All: Cylinder walls and buttresses; Dome and ring girder	Direct Flow Fire Barrier Flood Barrier Heat Sink Missile Barrier Pipe Whip Restraint Pressure Boundary Radiation Shielding Shelter SR Support NSR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program			26

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Indoor - All: Internal structure - Columns, beams, slabs, and walls	Direct Flow Fire Barrier Flood Barrier Heat Sink Missile Barrier Pipe Whip Restraint Radiation Shielding Shelter SR Support NSR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Elastomer/ Borated Water - All: RV cavity seal ring	Pressure Boundary	Elastomer	Treated Water - Borated, T<140°F (External)	Change in Mat'l Properties due to Elevated Temp.	Periodic Surveillance and Preventive Maintenance Program	(VII.A3.2-d)	(3.3.1-02)	35, 4
				Cracking due to Elevated Temperature	Periodic Surveillance and Preventive Maintenance Program	(VII.A3.2-d)	(3.3.1-02)	35, 4
				Cracking due to Ultraviolet Radiation and Ozone	Periodic Surveillance and Preventive Maintenance Program	(VII.A3.2-d)	(3.3.1-02)	35, 4

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Elastomer/ Indoor - All: Airlock door seals, Penetrations - electrical	Pressure Boundary	Elastomer	Indoor - No Air Conditioning (External)	Change in Mat'l Properties due to Elevated Temp.	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.3-a	3.5.1-06	B
				Cracking due to Elevated Temperature	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.3-a	3.5.1-06	B
				Cracking due to Ultraviolet Radiation and Ozone	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.3-a	3.5.1-06	B
Grout/Indoor - All: Column baseplates; Miscellaneous steel structures	Support NSR Support SR	Grout	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Structural Carbon Steel Fasteners/Indoor - All: Dome truss; Miscellaneous steel structures; Cast-in place anchor bolts	Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B5.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.A4.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Indoor - All: Airlocks and equipment hatches including bolting	Fire Barrier Pressure Boundary	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.2-a	3.5.1-04	B, 24
				Loss of Material due to Wear	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.2-b	3.5.1-05	B
Structural Carbon Steel/Indoor - All: Containment liner & keyway channels	Direct Flow Heat Sink Pipe Whip Restraint Pressure Boundary Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A1.2-a	3.5.1-12	B, 24
					Boric Acid Corrosion Program	II.A1.2-a	3.5.1-12	E, 6, 24
				Loss of Material due to General Corrosion	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A1.2-a	3.5.1-12	B, 24

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Indoor - All: Exposed portions of embedded steel; Framing - Columns, beams, bracing, baseplates, dome truss, and crane supports; Platforms, grating, stairs, ladders, and checkered plates; CRDM missile shield	Direct Flow Heat Sink Missile Barrier Pipe Whip Restraint Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B5.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.A4.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Carbon Steel/Indoor - All: Penetrations - electrical	Fire Barrier Pressure Boundary	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	II.A3.1-a	3.5.1-03	E, 6, 24
				Loss of Material due to General Corrosion	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.1-a	3.5.1-03	B, 24

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Indoor - All: Penetrations, mechanical, including bolting.	Fire Barrier Pressure Boundary	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	II.A3.1-a	3.5.1-03	E, 6, 24
				Loss of Material due to General Corrosion	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.1-a	3.5.1-03	B, 24, 32
Structural Carbon Steel/Indoor - All: Post-tensioning tendons	Pressure Boundary Shelter SR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A1.3-a	3.5.1-15	B, 24, 25
Structural Copper Alloy/Indoor - All: Airlock bushings	Fire Barrier Pressure Boundary	Structural Copper Alloy (Zinc<15%)	Indoor - No Air Conditioning (External)	Loss of Material due to Wear	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	II.A3.2-b	3.5.1-05	F, 5
Structural Stainless Steel Fasteners/Indoor - All: Miscellaneous items	Support NSR Support SR	Structural Steel - Stainless	Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Stainless Steel/Borated Water -All: Refueling cavity liner; Sandbox covers including bolting; Plates, bars, strips, and rods associated with the RC; Fuel Transfer Tube including bolting	Fire Barrier Heat Sink Pressure Boundary Radiation Shielding	Structural Steel - Stainless	Treated Water - Borated, T<140°F (External)	Loss of Material due to Crevice Corrosion	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	III.A5.2-b	3.5.1-23	34, 30, 31
					Water Chemistry Control Program	III.A5.2-b	3.5.1-23	B, 30
				Loss of Material due to MIC	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	III.A5.2-b	3.5.1-23	5, 6, 30, 31
					Water Chemistry Control Program	III.A5.2-b	3.5.1-23	H, 5, 30
				Loss of Material due to Pitting Corrosion	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	III.A5.2-b	3.5.1-23	5, 6, 30, 31
					Water Chemistry Control Program	III.A5.2-b	3.5.1-23	H, 5, 30
Structural Stainless Steel/Indoor - All: Penetrations - electrical	Fire Barrier Pressure Boundary	Structural Steel - Stainless	Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.5.2-1 Structures and Component Supports - Containment Unit 1/2 Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Stainless Steel/Indoor - All: Miscellaneous Items, Reactor Cavity Liner	Direct Flow Heat Sink Support SR	Structural Steel - Stainless	Indoor - No Air Conditioning (External)	None	None Required			J
Structural Steel Piles/ Buried - All: Carbon steel H-piles - foundation	Support SR	Carbon Steel Foundation Piles	Buried (External)	None	None Required			J

Table 3.5.2-2 Structures and Component Supports - Control Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Spread footings	Shelter SR Support NSR Support SR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Walls, ceilings, floors, columns; Equipment pedestals; Spray walls (AFWP Rm)	Fire Barrier Flood Barrier Heat Sink HELB Shielding Missile Barrier Radiation Shielding Shelter SR Support NSR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Fire Protection Program			26
					Structures Monitoring Program			26
Concrete/ Outdoor - All: Wall - East	Fire Barrier Flood Barrier Missile Barrier Shelter SR Support SR	Concrete (Reinforced)	Outdoor (External)	None	Fire Protection Program			26
					Structures Monitoring Program			26

Table 3.5.2-2 Structures and Component Supports - Control Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Doors/Indoor - All: All doors throughout the building	Fire Barrier Flood Barrier	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Fire Protection Program	(VII.G.2-d)	(3.3.1-20)	H, 28, 29
				Loss of Material due to Wear	Fire Protection Program	(VII.G.2-d)	(3.3.1-20)	B, 28, 29
	HELB Shielding	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A1.2-a	3.5.1-20	B, 29
				Loss of Material due to Wear	Structures Monitoring Program	III.A1.2-a	3.5.1-20	H, 5, 29
Elastomers/ Indoor - All: Rubber flap - DGR louver; Rubber sill, Sweep - Flood doors; Gasket and seals - Control Room doors	Flood Barrier	Elastomer	Indoor - No Air Conditioning (External)	Change in Mat'l Properties due to Elevated Temp.	Fire Protection Program	(VII.F1.1-b)	(3.3.1-02)	E, 4
					Structures Monitoring Program	(VII.F1.1-b)	(3.3.1-02)	35, 4
				Cracking due to Elevated Temperature	Fire Protection Program	(VII.F1.1-b)	(3.3.1-02)	E, 4
					Structures Monitoring Program	(VII.F1.1-b)	(3.3.1-02)	35, 4
				Cracking due to Ultraviolet Radiation and Ozone	Fire Protection Program	(VII.F1.1-b)	(3.3.1-02)	E, 4
					Structures Monitoring Program	(VII.F1.1-b)	(3.3.1-02)	35, 4

Table 3.5.2-2 Structures and Component Supports - Control Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Glass/Indoor - All: Glass windows - Control Room wall (north, south, and east); Glass windows - Computer Rm (east wall)	HELB Shielding Shelter SR	Glass	Indoor - No Air Conditioning (External)	None	None Required			J
Grout/Indoor - All: Miscellaneous steel structures	Support NSR Support SR	Grout	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Masonry Block Wall/Outdoor - All: Diesel Generator Room (DGR) - East wall	Flood Barrier	Block Wall	Outdoor (External)	Cracking due to restraint, shrinkage, etc.	Structures Monitoring Program	III.A1.3-a	3.5.1-24	B
Masonry Block Walls/Indoor - All: Battery Room, Non-Vital Switchgear Room (Non-VSR), Control Room - Internal (CR), DGR and AFW Pump (AFWP) Rm tunnel	Fire Barrier	Block Wall	Indoor - No Air Conditioning (External)	Cracking due to restraint, shrinkage, etc.	Fire Protection Program	III.A1.3-a	3.5.1-24	34
					Structures Monitoring Program	III.A1.3-a	3.5.1-24	B
	Flood Barrier Shelter SR	Block Wall	Indoor - No Air Conditioning (External)	Cracking due to restraint, shrinkage, etc.	Structures Monitoring Program	III.A1.3-a	3.5.1-24	B

Table 3.5.2-2 Structures and Component Supports - Control Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel Fasteners/Indoor - All: Subsoil drain cover; Wall panels and plates, bracing; HELB and flood barriers; Door braces; Platforms, stairs	Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A1.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Carbon Steel Fasteners/ Outdoor - All: Missile shield - DGR; Corner plates - DGR (east wall)	Support NSR Support SR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A1.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-2 Structures and Component Supports - Control Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Indoor - All: HELB barriers - Cable Spreading Rm (CSR) north and south wall, Non-VSR - South wall and braces, and east wall barriers around cable trays; SW guard pipe - Battery Rm; CST supply guard pipe - 1E Battery Rm (26 EL); Door braces - VSR south and west walls; Wall plates - CSR north and south walls; Wall panels - CR north, south and east walls; Flood barrier - Non-VSR (east wall); Masonry wall bracing; Platforms, stairs	Flood Barrier HELB Shielding Shelter SR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A1.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-2 Structures and Component Supports - Control Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Outdoor - All: Missile barrier and bracing - DGR air intake	Missile Barrier Support SR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A1.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Cast Iron/Indoor - All: Floor drain covers and flanges (DGR, Vital Switchgear Room (VSR), AFWP Rm)	Flood Barrier	Structural Cast Iron	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program			J, 5
Wood/Outdoor - All: Missile shield - integral part of Diesel Generator air intake	Missile Barrier	Wood	Outdoor (External)	Change in Mat'l Properties due to Rot and Mildew	Structures Monitoring Program			J, 5
				Loss of Material due to Rot and Mildew	Structures Monitoring Program			J, 5

Table 3.5.2-3 Structures and Component Supports - Circulating Water Pumphouse Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - basemat	Shelter SR Support SR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Floors; Missile barrier; Non-combustible wall (SW Pumps)	Fire Barrier	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
		Fiber Reinforced Cement	Indoor - No Air Conditioning (External)	None	Fire Protection Program			26
	Flood Barrier Missile Barrier Shelter SR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Concrete/ Outdoor - All: Walls, roof	Fire Barrier Flood Barrier Missile Barrier Shelter SR Support SR	Concrete (Reinforced)	Outdoor (External)	None	Structures Monitoring Program			26
Concrete/Raw Water - All: Forebay structure and pump bays	Flood Barrier Shelter SR Support SR Water Source	Concrete (Reinforced)	Raw Water (Submerged) (External)	Loss of Material due to Abrasion/ Cavitation	Structures Monitoring Program	III.A6.1-h	3.5.1-22	E, 6

Table 3.5.2-3 Structures and Component Supports - Circulating Water Pumphouse Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Doors/Indoor - All: All doors throughout the building	Fire Barrier	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Fire Protection Program	(VII.G.1-d)	(3.3.1-20)	H, 29
				Loss of Material due to Wear	Fire Protection Program	(VII.G.1-d)	(3.3.1-20)	B, 29
Grout/Indoor - All: Column baseplates	Support SR	Grout	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Structural Carbon Steel Fasteners/Indoor - All: Structural steel framing	Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A6.2-a	3.5.1-22	E, 6, 24
Structural Carbon Steel/Indoor - All: Framing - Columns, beams	Missile Barrier Shelter SR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A6.2-a	3.5.1-22	E, 6, 24

Table 3.5.2-4 Structures and Component Supports - Diesel Generator Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Footings and basemat	Shelter SR Support NSR Support SR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Walls, floors and ceilings	Fire Barrier Missile Barrier Shelter SR Support NSR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Fire Protection Program			26
					Structures Monitoring Program			26
Concrete/ Outdoor - All: Walls, roof	Fire Barrier Missile Barrier Shelter SR Support NSR Support SR	Concrete (Reinforced)	Outdoor (External)	None	Fire Protection Program			26
					Structures Monitoring Program			26
Doors/Outdoor - All: All doors throughout the building	Fire Barrier Support NSR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Fire Protection Program	(VII.G.4-d)	(3.3.1-20)	H, 29
				Loss of Material due to Wear	Fire Protection Program	(VII.G.4-d)	(3.3.1-20)	B, 29
Doors/Indoor - All: All doors throughout the building	Fire Barrier	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Fire Protection Program	(VII.G.4-d)	(3.3.1-20)	H, 29
				Loss of Material due to Wear	Fire Protection Program	(VII.G.4-d)	(3.3.1-20)	B, 29

Table 3.5.2-4 Structures and Component Supports - Diesel Generator Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Grout/Indoor - All: Platforms, stairs	Support NSR Support SR	Grout	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Structural Carbon Steel Fasteners/Indoor - All: Platforms, stairs; Missile shields	Support NSR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Carbon Steel Fasteners/ Outdoor - All: Missile shields	Support NSR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Carbon Steel/Indoor - All: Framing - Crane rails supports; Platforms, stairs	Support NSR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Carbon Steel/Outdoor - All: Missile shields; Wall plates at missile shields	Missile Barrier Support NSR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-5 Structures and Component Supports - Facade Unit 1/2 Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Spread footings	Support NSR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Floor	Support NSR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Concrete/ Outdoor - All: Retaining walls	Support NSR	Concrete (Reinforced)	Outdoor (External)	None	Structures Monitoring Program			26
Grout/Indoor - All: Column baseplates	Support NSR	Grout	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Masonry Bock Wall/Indoor - All: Elevators and stairs towers	Support NSR	Block Wall	Indoor - No Air Conditioning (External)	Cracking due to restraint, shrinkage, etc.	Structures Monitoring Program	III.A3.3-a	3.5.1-24	B
Structural Carbon Steel Fasteners/Indoor - All: Structural steel framing; Steel framing for elevator and stair towers	Support NSR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-5 Structures and Component Supports - Facade Unit 1/2 Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Indoor - All: Framing - Columns, beams; Roof truss	Support NSR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-6 Structures and Component Supports - Primary Auxiliary Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Boraflex/Borated Water - All: Spent fuel storage racks	Maintain Subcriticality	Boraflex	Treated Water - Borated, T<140°F (External)	Red. of Neutron-Absorb. Cap./Boraflex Degrad.	Boraflex Monitoring Program	(VII.A2.1-a)	(3.3.1-12)	B
Concrete/Buried - All: Foundation - Basemat	Shelter SR Support NSR Support SR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Walls, ceilings, floors; Spent fuel pool	Fire Barrier Flood Barrier Missile Barrier Shelter SR Support NSR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Fire Protection Program			26
					Structures Monitoring Program			26
Concrete/ Outdoor - All: Walls	Fire Barrier Missile Barrier Shelter SR Support NSR Support SR	Concrete (Reinforced)	Outdoor (External)	None	Fire Protection Program			26
					Structures Monitoring Program			26

Table 3.5.2-6 Structures and Component Supports - Primary Auxiliary Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Doors/Indoor - All: All doors throughout the building	Fire Barrier Flood Barrier	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Fire Protection Program	(VII.G.3-d)	(3.3.1-20)	H, 29
				Loss of Material due to Wear	Fire Protection Program	(VII.G.3-d)	(3.3.1-20)	B, 29
	HELB Shielding	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a	3.5.1-20	B, 29
				Loss of Material due to Wear	Structures Monitoring Program	III.A3.2-a	3.5.1-20	H, 5, 29
Elastomer/ Borated Water - All: SFP gates	Pressure Boundary	Elastomer	Treated Water - Borated, T<140°F (External)	Change in Mat'l Properties due to Elevated Temp.	Periodic Surveillance and Preventive Maintenance Program	(VII.A3.2-d)	(3.3.1-02)	35, 4
				Cracking due to Elevated Temperature	Periodic Surveillance and Preventive Maintenance Program	(VII.A3.2-d)	(3.3.1-02)	35, 4
				Cracking due to Ultraviolet Radiation and Ozone	Periodic Surveillance and Preventive Maintenance Program	(VII.A3.2-d)	(3.3.1-02)	35, 4

Table 3.5.2-6 Structures and Component Supports - Primary Auxiliary Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Elastomers/ Indoor - All: Rubber sill, Sweep - Flood doors	Flood Barrier	Elastomer	Indoor - No Air Conditioning (External)	Change in Mat'l Properties due to Elevated Temp.	Fire Protection Program	(VII.F1.1-b)	(3.3.1-02)	E, 4
					Structures Monitoring Program	(VII.F1.1-b)	(3.3.1-02)	35, 4
				Cracking due to Elevated Temperature	Fire Protection Program	(VII.F1.1-b)	(3.3.1-02)	E, 4
					Structures Monitoring Program	(VII.F1.1-b)	(3.3.1-02)	35, 4
				Cracking due to Ultraviolet Radiation and Ozone	Fire Protection Program	(VII.F1.1-b)	(3.3.1-02)	E, 4
					Structures Monitoring Program	(VII.F1.1-b)	(3.3.1-02)	35, 4
Grout/Indoor - All: Columns baseplates; Miscellaneous steel structures	Support NSR Support SR	Grout	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Masonry Block Wall/Indoor - All: Block walls (8', 26', 46' EL)	Fire Barrier	Block Wall	Indoor - No Air Conditioning (External)	Cracking due to restraint, shrinkage, etc.	Fire Protection Program	III.A3.3-a	3.5.1-24	34
					Structures Monitoring Program	III.A3.3-a	3.5.1-24	B
	Shelter SR	Block Wall	Indoor - No Air Conditioning (External)	Cracking due to restraint, shrinkage, etc.	Structures Monitoring Program	III.A3.3-a	3.5.1-24	B

Table 3.5.2-6 Structures and Component Supports - Primary Auxiliary Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel Fasteners/Indoor - All: Structural steel framing	Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B5.1-b	3.5.1-31	G, 5
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Carbon Steel Piles/Buried - All: Spent fuel pool	Support SR	Carbon Steel Foundation Piles	Buried (External)	None	None Required			J
Structural Carbon Steel/Indoor -All: Crane support girders; Framing - Columns, beams; Roof truss; Platforms, stairs	Direct Flow Shelter SR Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B5.1-b	3.5.1-31	G, 5
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Stainless Steel/Borated Water - All: Spent fuel pool; SFP canal; SFP gates	Pressure Boundary	Structural Steel - Stainless	Treated Water - Borated, T<140°F (External)	Loss of Material due to Crevice Corrosion	Water Chemistry Control Program	III.A5.2-b	3.5.1-23	B
				Loss of Material due to MIC	Water Chemistry Control Program	III.A5.2-b	3.5.1-23	H, 5
				Loss of Material due to Pitting Corrosion	Water Chemistry Control Program	III.A5.2-b	3.5.1-23	H, 5

Table 3.5.2-6 Structures and Component Supports - Primary Auxiliary Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Stainless Steel/Borated Water - All: Spent fuel storage racks	Support SR	Structural Steel - Stainless	Treated Water - Borated, T<140°F (External)	Loss of Material due to Crevice Corrosion	Water Chemistry Control Program	(VII.A2.1-c)	(3.3.1-13)	H, 5
				Loss of Material due to MIC	Water Chemistry Control Program	(VII.A2.1-c)	(3.3.1-13)	H, 5
				Loss of Material due to Pitting Corrosion	Water Chemistry Control Program	(VII.A2.1-c)	(3.3.1-13)	H, 5
Structural Stainless Steel/Indoor - All: New fuel storage racks	Support NSR	Structural Steel - Stainless	Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.5.2-7 Structures and Component Supports - Turbine Building Unit 1/2 Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Spread footings and basemat; Floor	Support NSR Support SR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Floors and walls (north, 8', 26' EL); Turbine Generator LO reservoir area curbing; LO storage tank area walls	Fire Barrier Support NSR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Concrete/ Outdoor - All: Foundation Walls	Support NSR Support SR	Concrete (Reinforced)	Outdoor (External)	None	Structures Monitoring Program			26
Grout/Indoor - All: Column baseplates	Support NSR Support SR	Grout	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Masonry Block Walls/Indoor - All: LO storage room walls (Unit 2 only)	Fire Barrier	Block Wall	Indoor - No Air Conditioning (External)	Cracking due to restraint, shrinkage, etc.	Structures Monitoring Program	III.A3.3-a	3.5.1-24	B

Table 3.5.2-7 Structures and Component Supports - Turbine Building Unit 1/2 Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel Fasteners/Indoor - All: Structural steel framing; HELB barriers; Flood louvers; Rollup door braces	Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Carbon Steel/Indoor - All: Flood louvers - East wall; Door bracing - East wall; HELB barrier - North wall; Crane rails supports; Framing - columns, beams; Roof truss	Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-8 Structures and Component Supports - Yard Structures - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Electrical Duct Banks; Equipment foundations and support pads; Manholes	Shelter SR Support NSR Support SR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Manhole interior	Shelter SR Support NSR Support SR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Concrete/ Outdoor -All: Equipment foundations and support pads; Manholes and covers	Fire Barrier Shelter SR Support NSR Support SR	Concrete (Reinforced)	Outdoor (External)	None	Structures Monitoring Program			26
Earthen Berm/ Outdoor - All: Berm Around FO Storage Tanks	Fire Barrier	Earth	Outdoor (External)	Loss of Material due to surface Runoff and Erosion	Structures Monitoring Program	III.A6.4-a	3.5.1-22	E, 6
Structural Carbon Steel Fasteners/ Outdoor - All: Switchyard equipment frames	Support NSR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24

Table 3.5.2-8 Structures and Component Supports - Yard Structures - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Outdoor - All: Manhole covers; Framing - 345K VAC distribution system; Bus ducts - HVSATs to circuit breaker cabinets; Bus ducts - LVSATs to 13.8K VAC switchgear cabinet	Support NSR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.A3.2-a, III.B5.1-a	3.5.1-20, 3.5.1-29	B, 24
Structural Cast Iron/Outdoor - All: Manhole frames and covers	Fire Barrier Shelter SR Support NSR	Structural Cast Iron	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program			J, 5
				Loss of Material due to Selective Leaching	Structures Monitoring Program			J, 5

Table 3.5.2-9 Structures and Component Supports - Cranes, Hoists, and Lifting Devices - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel Fasteners/Indoor - All: Rail hardware	Support NSR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	(VII.B.1-b)	(3.3.1-16)	B
Structural Carbon Steel/Indoor - All: Bridge and trolley framing; Crane rails, monorails; Lifting rigs	Support NSR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	(VII.B.1-b)	(3.3.1-16)	E, 6, 33
				Loss of Material due to Wear	Structures Monitoring Program	(VII.B.2-a)	(3.3.1-16)	B
Structural Stainless Steel/Borated Water - All: RV internals lifting rig	Support NSR	Structural Steel - Stainless	Treated Water - Borated, T<140°F (External)	Loss of Material due to Crevice Corrosion	Structures Monitoring Program	(VII.B.1-b)	(3.3.1-16)	F, G, 5
				Loss of Material due to MIC	Structures Monitoring Program	(VII.B.1-b)	(3.3.1-16)	F, G, 5
				Loss of Material due to Pitting Corrosion	Structures Monitoring Program	(VII.B.1-b)	(3.3.1-16)	F, G, 5

Table 3.5.2-10 Structures and Component Supports - Component Supports Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Elastomer/ Indoor - All: Equipment mount vibration isolators	Support NSR Support SR	Elastomer	Indoor - No Air Conditioning (External)	Change in Mat'l Properties due to Elevated Temp.	Structures Monitoring Program	III.B4.2-a	3.5.1-29	B
				Cracking due to Elevated Temperature	Structures Monitoring Program	III.B4.2-a	3.5.1-29	B
				Cracking due to Ultraviolet Radiation and Ozone	Structures Monitoring Program	III.B4.2-a	3.5.1-29	B
Grout/Indoor - All: Equipment and supports baseplates	Support NSR Support SR	Grout	Indoor - No Air Conditioning (External)	Cracking due to Service Induced Loadings	Structures Monitoring Program	III.B1.1.4-a, III.B1.2.3-a, III.B2.2-a, III.B3.2-a, III.B4.3-a	3.5.1-29	B
Grout/Outdoor - All: Equipment and supports baseplates	Support NSR	Grout	Outdoor (External)	Cracking due to Service Induced Loadings	Structures Monitoring Program	III.B2.2-a, III.B3.2-a, III.B4.3-a	3.5.1-29	B
High Strength Structural Carbon Steel Fasteners/Indoor - All: High strength structural fasteners - RCS component supports	Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B1.1.1-b, III.B1.2.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	ASME Section XI, Subsection IWF Inservice Inspection Program	III.B1.1.1-a	3.5.1-32	B

Table 3.5.2-10 Structures and Component Supports - Component Supports Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel Fasteners/Indoor - All: ASME equipment; ASME pipe supports and restraints	Support NSR Pipe Whip Restraint	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B1.1.1-b, III.B1.2.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.B1.1.1-a, III.B1.2.1-a	3.5.1-32	E, 27
	Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B1.1.1-b, III.B1.2.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	ASME Section XI, Subsection IWF Inservice Inspection Program	III.B1.1.1-a, III.B1.1.3-a, III.B1.2.1-a, III.B1.2.2-a	3.5.1-32	B
					Structures Monitoring Program	III.B1.1.1-a, III.B1.2.1-a	3.5.1-32	E, 27
Structural Carbon Steel Fasteners/Indoor - All: Equipment supports - Pipe restraints, mechanical equipment, HVAC ducts, panels and cabinets; Raceways; Miscellaneous steel structures	Pipe Whip Restraint Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B2.1-b, III.B3.1-b, III.B4.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.B2.1-a, III.B3.1-a, III.B4.1-a	3.5.1-29	B

Table 3.5.2-10 Structures and Component Supports - Component Supports Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel Fasteners/ Outdoor - All: G01/02 exhaust stack, Equipment supports - Yard	Support NSR Support SR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.B2.1-a, III.B3.1-a, III.B4.1-a	3.5.1-29	B
Structural Carbon Steel/Indoor - All: ASME pipe supports and restraints; ASME equipment supports	Support NSR Pipe Whip Restraint	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B1.1.1-b, III.B1.2.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.B1.1.1-a, III.B1.2.1-a	3.5.1-32	E, 27
	Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B1.1.1-b, III.B1.2.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	ASME Section XI, Subsection IWF Inservice Inspection Program	III.B1.1.1-a, III.B1.1.3-a, III.B1.2.1-a, III.B1.2.2-a	3.5.1-32	B
					Structures Monitoring Program	III.B1.1.1-a, III.B1.2.1-a	3.5.1-32	E, 27

Table 3.5.2-10 Structures and Component Supports - Component Supports Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Carbon Steel/Indoor - All: Framing - Structural shapes; Non-ASME pipe supports and restraints; Non-ASME equipment supports; HVAC duct supports; Raceways - Cable trays, metallic conduit, wireways; Electrical Enclosures - Panels, boxes, cabinets, consoles	Pipe Whip Restraint Support NSR Support SR	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to Boric Acid Wastage	Boric Acid Corrosion Program	III.B2.1-b, III.B3.1-b, III.B4.1-b	3.5.1-31	A
				Loss of Material due to General Corrosion	Structures Monitoring Program	III.B2.1-a, III.B3.1-a, III.B4.1-a	3.5.1-29	B
Structural Carbon Steel/Outdoor - All: G01/02 exhaust stack, Equipment supports - Yard	Support NSR Support SR	Structural Steel - Carbon	Outdoor (External)	Loss of Material due to General Corrosion	Structures Monitoring Program	III.B2.1-a, III.B3.1-a, III.B4.1-a	3.5.1-29	B

Table 3.5.2-10 Structures and Component Supports - Component Supports Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Structural Stainless Steel Fasteners/Indoor - All: Equipment/ component attachments (primarily NSSS)	Support NSR Support SR	Structural Steel - Stainless	Indoor - No Air Conditioning (External)	None	None Required			J
Structural Stainless Steel/Indoor - All: Structural plates (primarily NSSS piping)	Support NSR Support SR	Structural Steel - Stainless	Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.5.2-11 Structures and Component Supports - Fire Barrier Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Calcium Silicate Board/Indoor - All: Cable trays - Fire stop; Penetration seals	Fire Barrier	Calcium Silicate Board	Indoor - No Air Conditioning (External)	Cracking/ Delamination due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Loss of Material due to Abrasion	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5

Table 3.5.2-11 Structures and Component Supports - Fire Barrier Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Ceramic Fiber/Indoor - All: Cable trays - Fire stop; Penetration seals	Fire Barrier	Ceramic Fiber	Indoor - No Air Conditioning (External)	Cracking/ Delamination due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Loss of Material due to Abrasion	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Loss of Material due to Flaking	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5

Table 3.5.2-11 Structures and Component Supports - Fire Barrier Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Ceramic Fiber/Indoor - All: Cable trays - Fire stop; Penetration seals	Fire Barrier	Ceramic Fiber	Indoor - No Air Conditioning (External)	Separation due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
Ceramic Fiber-Board/ Indoor - All: Penetration seals	Fire Barrier	Ceramic Fiber Board	Indoor - No Air Conditioning (External)	Cracking/ Delamination due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Loss of Material due to Abrasion	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5

Table 3.5.2-11 Structures and Component Supports - Fire Barrier Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Ceramic Fiber-Board/ Indoor - All: Penetration seals	Fire Barrier	Ceramic Fiber Board	Indoor - No Air Conditioning (External)	Separation due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
Ceramic Fiber-Mat/Indoor - All: Cable trays - Fire stop	Fire Barrier	Ceramic Fiber Mat	Indoor - No Air Conditioning (External)	Cracking/ Delamination due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Loss of Material due to Abrasion	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Loss of Material due to Flaking	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5

Table 3.5.2-11 Structures and Component Supports - Fire Barrier Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Silicone Based Material/Indoor - All: Sprayed on mastic; Cable trays - Fire stop; Penetration seals; structural fireproofing	Fire Barrier	Silicone Based Materials	Indoor - No Air Conditioning (External)	Cracking/ Delamination due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Cracking/ Delamination due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Increased Hardness and Shrinkage due to Weathering	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	B
				Loss of Material due to Abrasion	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Movement	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
				Separation due to Shrinkage	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5

Table 3.5.2-11 Structures and Component Supports - Fire Barrier Commodity Group - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Silicone Based Material/Indoor - All: Sprayed on mastic; Cable trays - Fire stop; Penetration seals; structural fireproofing	Fire Barrier	Silicone Based Materials	Indoor - No Air Conditioning (External)	Separation due to Vibration	Fire Protection Program	(VII.G.1-a, VII.G.2-a, VII.G.3-a, VII.G.4-a)	(3.3.1-20)	H, 5
Stainless Steel Appurtenances/ Indoor - All: Tape, banding, banding seals, and wire for fire wraps and penetration seals	Fire Barrier	Stainless Steel	Indoor - No Air Conditioning (External)	None	None Required			J
Structural Carbon Steel/Indoor - All: Fire damper frames; Cable tray covers	Fire Barrier	Structural Steel - Carbon	Indoor - No Air Conditioning (External)	Loss of Material due to General Corrosion	Fire Protection Program	III.A3.2-a	(3.3.1-20)	E, 6

Table 3.5.2-12 Structures and Component Supports - 13.8 KV Switchgear Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Spread footing and basemat	Support NSR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Floor (integral with basemat)	Support NSR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Concrete/ Outdoor - All: Foundation - Spread footing and basemat	Support NSR	Concrete (Reinforced)	Outdoor (External)	None	Structures Monitoring Program			26

Table 3.5.2-13 Structures and Component Supports - Fuel Oil Pumphouse Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Basemat; Walls	Support NSR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Ceiling (25'-6'' EL)	Support NSR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Concrete/ Outdoor - All: Foundation - Basemat	Support NSR	Concrete (Reinforced)	Outdoor (External)	None	Structures Monitoring Program			26

Table 3.5.2-14 Structures and Component Supports - Gas Turbine Building Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Concrete/Buried - All: Foundation - Basemat	Support NSR	Concrete (Reinforced)	Buried (External)	None	Structures Monitoring Program			26
Concrete/Indoor - All: Floor; Equipment pedestals	Support NSR	Concrete (Reinforced)	Indoor - No Air Conditioning (External)	None	Structures Monitoring Program			26
Concrete/ Outdoor - All: Foundation - Basemat	Support NSR	Concrete (Reinforced)	Outdoor (External)	None	Structures Monitoring Program			26

Notes for Tables 3.5.2-1 through 3.5.2-14

A Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP has exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP has exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect but a different AMP is credited.

F Material not in NUREG-1801 for this component.

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

I Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-specific notes:

1 The CS Component asset was created to manage Boric Acid wastage of external surfaces only (for any carbon steel, low alloy steel, or cast iron component, including bolting), and therefore internal environments for this asset are not applicable. All other internal and external aging effects are identified separately under the specific component type.

2 Internal aging effects are not applicable. Due to the way data is entered into the LRDB, the internal environment of some components is listed as N/A (e.g. bolting, walls, clad vessels, structural steel, etc.).

3 Although the NUREG references a temperature gate of < 90 degrees C (200 degrees F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140 degrees F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The aging effect identified by PBNP (loss of material) for temperatures < 140 degrees F differs from that of the NUREG. That not withstanding, the Water Chemistry Control Program, which is credited

for managing the aging effects for all temperatures, will preclude the possibility of crack initiation and growth due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of the Chemistry program.

4 Plant specific program identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

5 Material/environment combination and/or aging effect not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

6 Program different than identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

7 There are no bolts with a specified minimum yield strength > 150 ksi in this system. Therefore, SCC is not an applicable aging effect/mechanism.

8 External aging effects are not applicable. Due to the way data is entered into the LRDB, the external environment of some components is listed as N/A (e.g. cladding, HX tubing, or other components that are entirely contained within another component).

9 AFW pump bearing coolers are integral to the bearing housing.

10 FE housing is CS but venturi is SS.

11 Internal portions of AFW turbine exhaust that are open to atmosphere.

12 Some components in this system experience a temperature below 200 degrees F, insufficient flow to support FAC, or operate less than 2% of the time. The components that fall in this category do not require aging management for FAC.

13 Some components are replaced on a specified frequency that precludes aging effects from resulting in loss of intended function. Periodic Surveillance and Preventive Maintenance Program is used to replace these components.

14 AFW Pump turbine casing's environment is more closely related to Main Steam environments, since it is not addressed in Chapter VIII.G Aux Feedwater System.

15 Components in this grouping do not have flow velocities >10 fps, and therefore loss of material due to erosion is not an aging effect requiring management.

16 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not

subject to temperatures where change in material properties or cracking could occur (>95 degrees F). Therefore no aging management is required.

17 SCC is not a concern for this material/environment group, due to temperatures being <140 degrees F.

18 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are subject to temperatures where change in material properties or cracking could occur (>95 degrees F).

19 Fuel Oil Chemistry Control Program is not necessary for managing the aging effects for a flame arrestor.

20 ISI inspections are not performed on this component, and therefore the ISI Program is not credited for managing the aging of this component.

21 Materials science supports loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The Water Chemistry Control Program is credited for managing the aging effects for all temperatures.

22 NUREG-1801 has loss of fracture toughness as an aging effect for this component. However, fluence levels for this component are below the threshold value, and therefore effects are not significant and do not require aging management.

23 NUREG-1801 credits the ISI Program for managing loss of material. PBNP does credit the ISI Program for managing cracking on this same component, and these inspections will identify loss of material/pitting, but only in the area of interest (at the weld). The Steam Generator Integrity Program is being included as it performs more general area inspections of the secondary side of the SGs. Previous visual inspections have confirmed no indications of loss of material.

24 This NUREG-1801 line item lists Loss of Material/Corrosion for the Aging Effect/Mechanism. This is interpreted to include the mechanisms of general and boric acid corrosion.

25 Tendon, loss of prestress NUREG-1801, line item 3.5.1-11/II.A1.3-b, is not addressed in this table. Refer to Section 4.0 on TLAAs.

26 No aging effects requiring management were identified for concrete (buried, indoor, or outdoor) and grout (except for Component Supports), however, concrete and grout is periodically monitored for potential degradation by an applicable license renewal program. See Appendix B for a discussion of the aging management programs used for concrete and grout.

27 Support (component or pipe) baseplates and their attachment to the structure (typically with embedded bolts or expansion anchors) are not within the scope of IWF and are considered

a part of the structure. However, for completeness, these items, including grout, are inspected when performing an IWF inspection. It is for this reason, that an ASME component support inspection will also be assigned against the Structures Monitoring Program.

28 The NUREG-1801 Volume I, line item 3.3.1-20, does not include the Control Building (Group 1 Structure), therefore, a comparable Group 3 Structure was chosen.

29 Doors that are assigned to the Structures Monitoring Program include those with the HELB function. Doors that are assigned to the Fire Protection Program include those with the fire or flood function. Note that some doors are common to both programs.

30 The Fire Barrier intended function is assigned to containment piping and electrical penetrations, fuel transfer tube, liner, and airlocks component types.

31 The fuel transfer tube is included with this component type (containment pressure boundary), therefore, the aging management program is appropriate.

32 Containment penetration sleeves, cracking/cyclic loading NUREG-1801, line item 3.5.1-2/II.A3.1-c, is not addressed in this table. Refer to Section 4.0 on TLAAs.

33 Crane, fatigue damage NUREG-1801, line item 3.3.1-3/VII.B.1-a, is not addressed in this table. Refer to Section 4.0 on TLAAs.

34 Consistent with NUREG-1801 for material, environment, aging effect and an additional AMP is credited.

35 Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter.

36 The material identified in this NUREG-1801 line item is stainless steel. The aging effects of stainless steel are the same as those for Cast Austenitic Stainless Steel at temperatures < 482 degrees F.

37 Unit 1 inspection port bolting has been identified by Westinghouse as being fatigue sensitive and needing replacement every 12 years. The Periodic Surveillance and Preventive Maintenance Program will be used to replace this bolting on a 10 year frequency.

38 The Unit 2 Steam Generators were designed and fabricated to eliminate the need for certain Section XI weld examinations. The Unit 2 transition cones are fabricated such that the girth welds are not at the discontinuity, and therefore Section XI does not require these welds to be periodically inspected. The steam nozzles were also fabricated integral to the elliptical head, and therefore there is no steam nozzle weld to inspect.

39 The One-Time Inspection is only for the letdown orifices, which is in response to NRC IN 98-045, “Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds.”

40 The Fuel Oil Chemistry Control Program includes provisions for performing tests/inspections for detecting tank wall loss.

41 In some cases where the Water Chemistry Control Program is not a viable option and aging effects are not expected to be significant, the One-Time Inspection Program alone is credited for managing aging effects. The One-Time Inspection Program has provisions to increase frequency of inspections based on the results of the first inspection.

Section 3.5 References

1. WCAP-14756-A, Aging Management Evaluation for Pressurized Water Reactor Containment Structure, May 2001.
2. WCAP-14422, Rev. 2-A, License Renewal Evaluation: Aging Management for Reactor Coolant System Supports, December 2000.

3.6 Aging Management of Electrical and Instrumentation and Controls

Since passive electrical components do not have internal environments in the same sense that mechanical components do, the term ohmic heating (Reference 1) is used to describe the effect of resistive heating that may occur in electrical components. This heating can result in the component having a service temperature that is hotter than the ambient conditions. Ohmic heating is only applicable to components that carry significant current, and therefore instrumentation circuits, such as Resistance Temperature Detectors (RTDs), Thermocouples, and related loop wiring is considered not to be subject to ohmic heating. For those components that are subject to ohmic heating (i.e., power cables, phase bus) the ultimate temperature is a result of the ambient temperature and the square of the ratio of the actual current to the ampacity of the conductor. Plant design guidelines do not normally permit a cable to be loaded to more than 80% of ampacity.

For the review of passive electrical commodities, the environments discussed in Section 3.0.1.2 were used.

Most organic materials used as electrical insulators were first evaluated against the environment “Containment” to determine if aging effects required management. This environment is considered conservative for normal ambient temperature and radiation dose.

PBNP includes installations of underground passive electrical components (cables). Of those, PBNP has medium-voltage power and control cables installed in underground duct banks. The functions of these cables were reviewed and evaluated against the environment “Raw Water (Submerged).”

The switchyard components and a limited number of exposed cables are addressed in the environment of “Outdoor.” These components are subject to normal environmental conditions, including precipitation.

Aging Effects Requiring Management

After the components requiring aging management review were identified and grouped by materials of construction and environment, a review of industry and plant-specific operating experience was performed. The purpose of this review was to assure that all applicable aging effects were identified, and to evaluate the effectiveness of existing aging management programs. This experience review was performed utilizing various industry and plant-specific programs and databases. Industry operating experience sources included NRC Generic Publications (including Information Notices, Circulars, Bulletins, and Generic Letters), INPO Significant Operating Event Reports (SOER), EPRI Technical Reports, and other information sources, such as the Sandia Aging

Management Guidelines for Electrical Cable and Terminations, and the Generic Aging Lessons Learned (GALL) report. Plant specific operating experience sources included Semi-annual and Annual Reports to AEC/NRC, Abnormal Occurrence and Licensee Event Reports (LERs), Condition Reports (CRs), and Corrective Actions (CAs) identified from 1970 to the present. Information from these sources was compiled in various databases. Based upon the material of construction, the applicable environments, and operating experience the potential aging effects requiring management for each of the components was identified as documented in Table 3.6.1 and Table 3.6.2-1.

The most common aging effect for passive electrical components is electrical failure due to thermal/thermoxidative degradation of organics. Thermal life was evaluated using methodology similar to Appendix G of the Sandia Aging Management Guideline for Electrical Cables and Connections (Reference 1). In many cases, conservative assumptions were used to simplify the analysis. Thermal life was not used to determine the scope of components in the Cable Condition Monitoring Program. The program includes all in-scope, electrical cables and connections within specified plant spaces, and adequately addresses aging effects due to thermal conditions. Therefore, further review of the thermal aging results was not required for electrical cables and connections.

Electrical failure due to radiolysis and radiation induced oxidation is considered a significant aging effect only for those passive electrical components installed in containment. For these components, the moderate damage threshold for the materials were reviewed against expected radiation environments. Although the review identified very few susceptible materials, the results of the review were not used to determine the scope of the components in the Cable Condition Monitoring Program. The program includes all in-scope, electrical cables and connections within specified plant spaces, and adequately addresses aging effects due to radiation. Therefore, further review of the radiation induced aging effects was not required for electrical cables and connections.

Moisture induced electrical failure for in-scope passive electrical components is considered to be a significant aging effect at PBNP. Medium-voltage cables are known to experience water-treeing in a wet environment and the environment at PBNP that qualifies is the underground duct banks. As discussed previously, there are in-scope medium-voltage cables in the underground duct banks. Industry and plant operating experience does not support moisture as a significant stressor for other passive electrical components. The results of this review were not used to determine the scope of the components in the Cable Condition Monitoring Program. The program includes all in-scope, electrical cables and connections within specified plant spaces, and adequately addresses aging effects due to moisture.

3.6.1 Introduction

This section provides the results of the aging management review for those components identified in Section 2.5, Electrical and Instrumentation and Controls, 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.

- 120 VAC Vital Instrument Power System (Section 2.5.2)
- 125 VDC Power System (Section 2.5.3)
- 4160 VAC Power System (Section 2.5.4)
- 480 VAC Power System (Section 2.5.5)
- Control Rod Drive and Indication System and Nuclear Process Instrumentation (Section 2.5.6)
- Miscellaneous AC Power and Lighting System (Section 2.5.7)
- Offsite Power System (Section 2.5.8)
- Reactor Protection System (Section 2.5.9)
- Engineered Safety Features Actuation System (Section 2.5.10)
- Plant Communications System (Section 2.5.11)
- 13.8K VAC Power System (Section 2.5.12)
- Radiation Monitoring System (Section 2.5.13)

Table 3.6.1, Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components, provides the summary of the programs evaluated in NUREG-1801 for the Electrical Component groups that are relied on for license renewal.

This table uses the format described in Section 3.0 above. Note that this table only includes those component groups that are applicable to a PWR.

3.6.2 Results

The following table summarizes the results of the aging management review for systems in the Electrical Components group:

Table 3.6.2-1, Electrical Components - Electrical Commodity Groups - Summary of Aging Management Evaluation

The materials that specific components are fabricated from, the environments to which components are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above systems in the following subsections of Section 3.6.2.1, Materials, Environment, Aging Effects Requiring Management and Aging Management Programs:

Section 3.6.2.1.1, 120 VAC Vital Instrument Power System

Section 3.6.2.1.2, 125 VDC Power System

Section 3.6.2.1.3, 4160 VAC Power System

Section 3.6.2.1.4, 480 VAC Power System

Section 3.6.2.1.5, Control Rod Drive and Indication System and Nuclear Process Instrumentation

Section 3.6.2.1.6, Miscellaneous AC Power and Lighting System

Section 3.6.2.1.7, Offsite Power System

Section 3.6.2.1.8, Reactor Protection System

Section 3.6.2.1.9, Engineered Safety Features Actuation System

Section 3.6.2.1.10, Plant Communications System

Section 3.6.2.1.11, 13.8K VAC Power System

Section 3.6.2.1.12, Radiation Monitoring System

3.6.2.1 Materials, Environment, Aging Effects Requiring Management and Aging Management Programs

3.6.2.1.1 120 VAC Vital Instrument Power System

Materials

The materials of construction for the 120 VAC Vital Instrument Power System components are:

- Connections - various metals
- Insulation materials
- Insulation materials - various organic polymers

Environment

The 120 VAC Vital Instrument Power System components are exposed to the following environments:

- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)

Aging Effects Requiring Management

The following aging effects, associated with the 120 VAC Vital Instrument Power System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the 120 VAC Vital Instrument Power System components:

- Cable Condition Monitoring Program

3.6.2.1.2 125 VDC Power System

Materials

The materials of construction for the 125 VDC Power System components are:

- Connections - various metals
- Insulation materials
- Insulation materials - various organic polymers

Environment

The 125 VDC Power System components are exposed to the following environments:

- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)

Aging Effects Requiring Management

The following aging effects, associated with the 125 VDC Power System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the 125 VDC Power System components:

- Cable Condition Monitoring Program
- Environmental Qualification Program

3.6.2.1.3 4160 VAC Power System

Materials

The materials of construction for the 4160 VAC Power System components are:

- Connections - various metals
- Copper
- Insulation materials - various organic polymers
- Porcelain
- Steel

Environment

The 4160 VAC Power System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Containment (External)
- Outdoor (External)
- Raw Water (Submerged) (External)

Aging Effects Requiring Management

The following aging effects, associated with the 4160 VAC Power System, require management:

- Formation of water trees, localized damage
- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the 4160 VAC Power System components:

- Boric Acid Corrosion Program
- Cable Condition Monitoring Program

3.6.2.1.4 480 VAC Power System

Materials

The materials of construction for the 480 VAC Power System components are:

- Connections - various metals
- Copper
- Insulation materials - various organic polymers
- Porcelain
- Steel

Environment

The 480 VAC Power System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Containment (External)

Aging Effects Requiring Management

The following aging effects, associated with the 480 VAC Power System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the 480 VAC Power System components:

- Boric Acid Corrosion Program
- Cable Condition Monitoring Program
- Environmental Qualification Program

3.6.2.1.5 Control Rod Drive and Indication System and Nuclear Process Instrumentation

Materials

The materials of construction for the Control Rod Drive and Indication and Nuclear Process Instrumentation System components are:

- Connections - various metals

- Insulation materials
- Insulation materials - various organic polymers

Environment

The Control Rod Drive and Indication and Nuclear Process Instrumentation System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Containment (External)

Aging Effects Requiring Management

The following aging effects, associated with the Control Rod Drive and Indication and Nuclear Process Instrumentation System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the Control Rod Drive and Indication System and Nuclear Process Instrumentation components:

- Boric Acid Corrosion Program
- Cable Condition Monitoring Program
- Environmental Qualification Program

3.6.2.1.6 Miscellaneous AC Power and Lighting System

Materials

The materials of construction for the Miscellaneous AC Power and Lighting System components are:

- Connections - various metals
- Insulation materials
- Insulation materials - various organic polymers

Environment

The Miscellaneous AC Power and Lighting System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Containment (External)

Aging Effects Requiring Management

The following aging effects, associated with the Miscellaneous AC Power and Lighting System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the Miscellaneous AC Power and Lighting System components:

- Boric Acid Corrosion Program
- Cable Condition Monitoring Program

3.6.2.1.7 Offsite Power System

Materials

The materials of construction for the Offsite Power System components are:

- Aluminum
- Cement
- Connections - various metals
- Galvanized metal
- Insulation materials - various organic polymers
- Metal
- Porcelain
- Stainless steel
- Steel

Environment

The Offsite Power System components are exposed to the following environments:

- Indoor - No Air Conditioning (External)
- Outdoor (External)

Aging Effects Requiring Management

The following aging effects, associated with the Offsite Power System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the Offsite Power System components:

- Cable Condition Monitoring Program

3.6.2.1.8 Reactor Protection System

Materials

The materials of construction for the Reactor Protection System components are:

- Connections - various metals
- Insulation materials
- Insulation materials - various organic polymers

Environment

The Reactor Protection System components are exposed to the following environments:

- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Containment (External)

Aging Effects Requiring Management

The following aging effects, associated with the Reactor Protection System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Protection System components:

- Cable Condition Monitoring Program
- Environmental Qualification Program

3.6.2.1.9 Engineered Safety Features Actuation System

Materials

The materials of construction for the Engineered Safety Features Actuation System components are:

- Connections - various metals
- Insulation materials
- Insulation materials - various organic polymers

Environment

The Engineered Safety Features Actuation System components are exposed to the following environments:

- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Containment (External)

Aging Effects Requiring Management

The following aging effects, associated with the Engineered Safety Features Actuation System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the Engineered Safety Features Actuation System components:

- Cable Condition Monitoring Program
- Environmental Qualification Program

3.6.2.1.10 Plant Communications System

Materials

The materials of construction for the Plant Communications System components are:

- Connections - various metals
- Insulation materials
- Insulation materials - various organic polymers

Environment

The Plant Communications System components are exposed to the following environments:

- Borated Water Leaks (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)
- Containment (External)

Aging Effects Requiring Management

The following aging effects, associated with the Plant Communications System, require management:

- Connector failure
- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the Plant Communications System components:

- Boric Acid Corrosion Program
- Cable Condition Monitoring Program

3.6.2.1.11 13.8K VAC Power System

Materials

The materials of construction for the 13.8K VAC Power System components are:

- Aluminum
- Connections - various metals

- Copper
- Fiberglass
- Insulation materials - various organic polymers
- Noryl
- Porcelain
- Silicone
- Stainless steel
- Steel

Environment

The 13.8K VAC Power System components are exposed to the following environments:

- Indoor - No Air Conditioning (External)
- Indoor - Air Conditioning (External)
- Outdoor (External)
- Raw Water (Submerged) (External)

Aging Effects Requiring Management

The following aging effects, associated with the 13.8K VAC Power System, require management:

- Formation of water trees, localized damage
- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the 13.8K VAC Power System components:

- Cable Condition Monitoring Program

3.6.2.1.12 **Radiation Monitoring System**

Materials

The materials of construction for the Radiation Monitoring System components are:

- Connections - various metals
- Insulation materials

- Insulation materials - various organic polymers

Environment

The Radiation Monitoring System components are exposed to the following environments:

- Borated Water Leaks (External)
- Containment (External)
- Indoor - Air Conditioning (External)
- Indoor - No Air Conditioning (External)

Aging Effects Requiring Management

The following aging effects, associated with the Radiation Monitoring System, require management:

- Reduced insulation resistance (IR), electrical failure

Aging Management Programs

The following aging management programs manage the aging effects for the Radiation Monitoring System components:

- Boric Acid Corrosion Program
- Cable Condition Monitoring Program
- Environmental Qualification Program

3.6.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

NUREG-1801 Volume 1 Tables provide the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Electrical and Instrumentation and Controls, those programs are addressed in the following sections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Environmental qualification of electrical equipment is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed separately in Section 4.8.1.

3.6.2.3 Time-Limited Aging Analysis

The time-limited aging analyses (TLAA) identified below are associated with the Electrical and Instrumentation and Controls components. The section of the LRA that contains the TLAA review results is indicated in parenthesis.

- EQ (Section 4.8.1, Environmental Qualification (EQ) of Electrical Equipment)

3.6.3 Conclusion

The Electrical and Instrumentation and Controls components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Electrical and Instrumentation and Controls components are identified in the summaries in Section 3.6.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the Electrical and Instrumentation and Controls components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.6.1 Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-01	Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements	Degradation due to various aging mechanisms	Environmental qualification of electric components	Yes, TLAA (see [SRP] subsection 3.6.2.2.1)	Further evaluation documented in Section 3.6.2.2.1.
3.6.1-02	Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure caused by thermal/ thermoxidative degradation of organics; radiolysis and photolysis (ultraviolet [UV] sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Aging management program for electrical cables and connections not subject to 10 CFR 50.49 EQ requirements	No	The Cable Condition Monitoring Program will adequately manage the potential aging effects for this component.

Table 3.6.1 Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-03	Electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (IR)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/ thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	Aging management program for electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements	No	The Cable Condition Monitoring Program will adequately manage the potential aging effects for this component.
3.6.1-04	Inaccessible medium-voltage (2K VAC to 15K VAC) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements	Formation of water trees, localized damage leading to electrical failure (breakdown of insulation); water trees caused by moisture intrusion	Aging management program for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements	No	The Cable Condition Monitoring Program will adequately manage the potential aging effects for this component.
3.6.1-05	Electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage	Corrosion of connector contact surfaces caused by intrusion of borated water	Boric acid corrosion	No	Consistent with NUREG-1801. Corrosion of connectors due to Boric Acid Corrosion is an aging effect requiring management. The Boric Acid Corrosion Program effectively manages corrosion of contact surfaces caused by the intrusion of borated water.

Table 3.6.2-1 Electrical Components - Electrical Commodity Groups - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Electrical cables and connections subject to 10 CFR 50.49 EQ requirements (125VDC, 480VAC, Reactor Protection, ESF Actuation, Nuclear Instrumentation, and Radiation Monitoring Systems)	Deliver Voltage, Current, or Signal Electrically Isolate and Support	Insulation Materials - Various Organic Polymers	Containment (External) Indoor - Air Conditioning (External) Indoor - No Air Conditioning (External)	Reduced Insulation Resistance (IR), Electrical Failure	Environmental Qualification Program	VI.B.1-a	3.6.1-01	A
Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements (All Electrical Power and I&C Systems)	Deliver Voltage, Current, or Signal	Insulation Materials - Various Organic Polymers	Containment (External) Indoor - Air Conditioning (External) Indoor - No Air Conditioning (External) Outdoor (External)	Reduced Insulation Resistance (IR), Electrical Failure	Cable Condition Monitoring Program	VI.A.1-a	3.6.1-02	B

Table 3.6.2-1 Electrical Components - Electrical Commodity Groups - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation (Nuclear Instrumentation and Radiation Monitoring Systems)	Deliver Voltage, Current, or Signal	Insulation Materials - Various Organic Polymers	Containment (External) Indoor - Air Conditioning (External) Indoor - No Air Conditioning (External)	Reduced Insulation Resistance (IR), Electrical Failure	Cable Condition Monitoring Program	VI.A.1-b	3.6.1-03	B
Electrical connections not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage (Some Electrical and I&C Systems)	Deliver Voltage, Current, or Signal	Connections and Connector Pins - Various Metals	Borated Water Leaks (External)	Connector Failure	Boric Acid Corrosion Program	VI.A.2-a	3.6.1-05	A
			Containment (External) Indoor - No Air Conditioning (External)	None	None Required			J

Table 3.6.2-1 Electrical Components - Electrical Commodity Groups - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Electrical penetration assemblies (Electrical Power Systems 4160 VAC or less, and all I&C Systems)	Deliver Voltage, Current, or Signal	Insulation Materials	Containment (External) Indoor - No Air Conditioning (External)	Reduced Insulation Resistance (IR), Electrical Failure	Cable Condition Monitoring Program	VI.A.1-a	3.6.1-02	B
					Environmental Qualification Program	VI.B.1-a	3.6.1-01	A
High-voltage insulators (Offsite Power System)	Electrically Isolate and Support	Porcelain Metal Cement	Outdoor (External)	None	None Required			J
Inaccessible medium-voltage (2K VAC to 15K VAC) cables and connections (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements (4160 VAC and 13.8K VAC Power Systems)	Deliver Voltage, Current, or Signal	Insulation Materials - Various Organic Polymers	Indoor - No Air Conditioning (External) Raw Water (Submerged) (External) Indoor - Air Conditioning (External) Outdoor (External)	Formation of Water Trees, Localized Damage	Cable Condition Monitoring Program	VI.A.1-c	3.6.1-04	B

Table 3.6.2-1 Electrical Components - Electrical Commodity Groups - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG -1801 Volume 2 Line Item	Table 1 Item	Notes
Phase bus (480 VAC, 4160 VAC, and 13.8K VAC Power Systems)	Deliver Voltage, Current, or Signal	Copper	Indoor - No Air Conditioning (External) Indoor - Air Conditioning (External)	None	None Required			J
	Electrically Isolate and Support	Fiberglass Bronze Noryl Stainless Steel Porcelain Silicone Steel Aluminum	Indoor - No Air Conditioning (External) Indoor - Air Conditioning (External)	None	None Required			J
Switchyard buses and connections (Offsite Power System)	Deliver Voltage, Current, or Signal	Aluminum Galvanized Metal Stainless Steel	Outdoor (External)	Water Ingress Expansion Cracking	Cable Condition Monitoring Program			B
Transmission conductors (Offsite Power System)	Deliver Voltage, Current, or Signal	Aluminum Steel	Outdoor (External)	None	None Required			J

Notes for Table 3.6.2-1

A Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging management program. AMP has exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 for material, environment, aging effect and AMP. AMP has exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect but a different AMP is credited.

F Material not in NUREG-1801 for this component.

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

I Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-specific notes:

1 The CS Component asset was created to manage Boric Acid wastage of external surfaces only (for any carbon steel, low alloy steel, or cast iron component, including bolting), and therefore internal environments for this asset are not applicable. All other internal and external aging effects are identified separately under the specific component type.

2 Internal aging effects are not applicable. Due to the way data is entered into the LRDB, the internal environment of some components is listed as N/A (e.g. bolting, walls, clad vessels, structural steel, etc.).

3 Although the NUREG references a temperature gate of < 90 degrees C (200 degrees F) and a single aging effect (cracking due to SCC), materials science supports (1) a temperature gate > 140 degrees F for cracking due to SCC, and (2) loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The aging effect identified by PBNP (loss of material) for temperatures < 140 degrees F differs from that of the NUREG. That not withstanding, the Water Chemistry Control Program, which is credited

for managing the aging effects for all temperatures, will preclude the possibility of crack initiation and growth due to SCC. A One-Time Inspection Program is also credited to verify the adequacy of the Chemistry program.

4 Plant specific program identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

5 Material/environment combination and/or aging effect not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

6 Program different than identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

7 There are no bolts with a specified minimum yield strength > 150 ksi in this system. Therefore, SCC is not an applicable aging effect/mechanism.

8 External aging effects are not applicable. Due to the way data is entered into the LRDB, the external environment of some components is listed as N/A (e.g. cladding, HX tubing, or other components that are entirely contained within another component).

9 AFW pump bearing coolers are integral to the bearing housing.

10 FE housing is CS but venturi is SS.

11 Internal portions of AFW turbine exhaust that are open to atmosphere.

12 Some components in this system experience a temperature below 200 degrees F, insufficient flow to support FAC, or operate less than 2% of the time. The components that fall in this category do not require aging management for FAC.

13 Some components are replaced on a specified frequency that precludes aging effects from resulting in loss of intended function. Periodic Surveillance and Preventive Maintenance Program is used to replace these components.

14 AFW Pump turbine casing's environment is more closely related to Main Steam environments, since it is not addressed in Chapter VIII.G Aux Feedwater System.

15 Components in this grouping do not have flow velocities >10 fps, and therefore loss of material due to erosion is not an aging effect requiring management.

16 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not

subject to temperatures where change in material properties or cracking could occur (>95 degrees F). Therefore no aging management is required.

17 SCC is not a concern for this material/environment group, due to temperatures being <140 degrees F.

18 Elastomer (neoprene, rubber, etc.) components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. These locations are subject to temperatures where change in material properties or cracking could occur (>95 degrees F).

19 Fuel Oil Chemistry Control Program is not necessary for managing the aging effects for a flame arrestor.

20 ISI inspections are not performed on this component, and therefore the ISI Program is not credited for managing the aging of this component.

21 Materials science supports loss of material due to pitting (stagnant or low flow conditions) and crevice corrosion for all temperatures. The Water Chemistry Control Program is credited for managing the aging effects for all temperatures.

22 NUREG-1801 has loss of fracture toughness as an aging effect for this component. However, fluence levels for this component are below the threshold value, and therefore effects are not significant and do not require aging management.

23 NUREG-1801 credits the ISI Program for managing loss of material. PBNP does credit the ISI Program for managing cracking on this same component, and these inspections will identify loss of material/pitting, but only in the area of interest (at the weld). The Steam Generator Integrity Program is being included as it performs more general area inspections of the secondary side of the SGs. Previous visual inspections have confirmed no indications of loss of material.

24 This NUREG-1801 line item lists Loss of Material/Corrosion for the Aging Effect/Mechanism. This is interpreted to include the mechanisms of general and boric acid corrosion.

25 Tendon, loss of prestress NUREG-1801, line item 3.5.1-11/II.A1.3-b, is not addressed in this table. Refer to Section 4.0 on TLAAs.

26 No aging effects requiring management were identified for concrete (buried, indoor, or outdoor) and grout (except for Component Supports), however, concrete and grout is periodically monitored for potential degradation by an applicable license renewal program. See Appendix B for a discussion of the aging management programs used for concrete and grout.

27 Support (component or pipe) baseplates and their attachment to the structure (typically with embedded bolts or expansion anchors) are not within the scope of IWF and are considered

a part of the structure. However, for completeness, these items, including grout, are inspected when performing an IWF inspection. It is for this reason, that an ASME component support inspection will also be assigned against the Structures Monitoring Program.

28 The NUREG-1801, Volume I, line item 3.3.1-20, does not include the Control Building (Group 1 Structure), therefore, a comparable Group 3 Structure was chosen.

29 Doors that are assigned to the Structures Monitoring Program include those with the HELB function. Doors that are assigned to the Fire Protection Program include those with the fire or flood function. Note that some doors are common to both programs.

30 The Fire Barrier intended function is assigned to containment piping and electrical penetrations, fuel transfer tube, liner, and airlocks component types.

31 The fuel transfer tube is included with this component type (containment pressure boundary), therefore, the aging management program is appropriate.

32 Containment penetration sleeves, cracking/cyclic loading NUREG-1801, line item 3.5.1-2/II.A3.1-c, is not addressed in this table. Refer to Section 4.0 on TLAAs.

33 Crane, fatigue damage NUREG-1801, line item 3.3.1-3/VII.B.1-a, is not addressed in this table. Refer to Section 4.0 on TLAAs.

34 Consistent with NUREG-1801 for material, environment, aging effect and an additional AMP is credited.

35 Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter.

36 The material identified in this NUREG-1801 line item is stainless steel. The aging effects of stainless steel are the same as those for Cast Austenitic Stainless Steel at temperatures < 482 degrees F.

37 Unit 1 inspection port bolting has been identified by Westinghouse as being fatigue sensitive and needing replacement every 12 years. The Periodic Surveillance and Preventive Maintenance Program will be used to replace this bolting on a 10 year frequency.

38 The Unit 2 Steam Generators were designed and fabricated to eliminate the need for certain Section XI weld examinations. The Unit 2 transition cones are fabricated such that the girth welds are not at the discontinuity, and therefore Section XI does not require these welds to be periodically inspected. The steam nozzles were also fabricated integral to the elliptical head, and therefore there is no steam nozzle weld to inspect.

39 The One-Time Inspection is only for the letdown orifices, which is in response to NRC IN 98-045, “Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds.”

40 The Fuel Oil Chemistry Control Program includes provisions for performing tests/inspections for detecting tank wall loss.

41 In some cases where the Water Chemistry Control Program is not a viable option and aging effects are not expected to be significant, the One-Time Inspection Program alone is credited for managing aging effects. The One-Time Inspection Program has provisions to increase frequency of inspections based on the results of the first inspection.

Section 3.6 References

1. SAND 96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,” Sandia National Laboratories for the U. S. Department of Energy, September 1996.
2. NUREG-1801, “Generic Aging Lessons Learned (GALL),” U. S. Nuclear Regulatory Commission, April 2001.
3. NUREG-1800, “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants,” U. S. Nuclear Regulatory Commission, April 2001.

4.0 TIME-LIMITED AGING ANALYSES

Two areas of plant technical assessment are required to support an application for a renewed operating license. The first area of technical review is the Integrated Plant Assessment, which is described in Sections 2 and 3 of this License Renewal Application. The second area of technical review required is the identification and evaluation of plant-specific time-limited aging analyses and exemptions. The identifications and evaluations included in this section meet the requirements contained in 10 CFR 54.21(c) and provide the information necessary for the NRC to make the finding contained in 10 CFR 54.29(a)(2).

4.1 Identification of Time-Limited Aging Analyses

Title 10 of the Code of Federal Regulations, Part 54 (10 CFR 54) sets forth the requirements for License Renewal of Operating Nuclear Power Plants. 10 CFR 54.21(c)(1) requires a listing and an evaluation of Time Limited Aging Analyses (TLAAs). 10 CFR 54.21(c)(2) requires a listing and evaluation of active plant-specific exemptions granted under 10 CFR 50.12 that are based on TLAAs as defined in 10 CFR 54.3(a). The overall TLAA methodology is provided in Figure 4.1-1.

4.1.1 Identification Process of Time-Limited Aging Analyses

This section documents the identification and disposition of Time Limited Aging Analyses (TLAAs), including TLAA related exemptions granted in accordance with 10 CFR 50.12, which are applicable to PBNP for the period of extended operation.

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 current licensing basis.

Potential TLAAs, which could meet these 6 criteria, can be identified in two ways:

- Reviewing lists of previously identified TLAAs and choosing those generically applicable to PBNP for further evaluation.
- Searching the PBNP Current Licensing Basis (CLB) for calculation/analyses with a time-sensitive element.

4.1.1.1 TLAA Industry Related Search

Industry License Renewal related documents, including previous applications by other plants, have already identified a number of TLAAs. These TLAAs tend to be generically applicable to other similar type plants (e.g. PWR plants). These documents were searched to identify a list of known TLAAs, which could be potentially applicable to PBNP.

Methodology

The following documents were searched for typical TLAAs which could potentially be applicable to PBNP:

- Standard Review Plan for License Renewal Chapter 4
- NEI 95-10
- Statements of Consideration for 10 CFR 54
- WOG Generic Technical Reports
- Previously submitted License Renewal Applications for other plants

Industry Results

The TLAAs shown below were identified as potentially applicable to PBNP:

1. Reactor Vessel Pressurized Thermal Shock
2. Reactor Vessel Upper Shelf Energy
3. Reactor Vessel Pressure/Temperature Limits
4. Reactor Vessel Structural Integrity Including CRDMs and Internals
5. Pressurizer Surge Line Evaluation
6. Pressurizer Structural Integrity
7. Steam Generator Structural Integrity
8. Reactor Coolant Pump Structural Integrity
9. Reactor Vessel Underclad Cracking

10. RCP Flywheel Inspection
11. Bottom Mounted Instrumentation Thimble Tube Wear
12. Emergency Containment Cooling Tube Wear
13. ANSI B31.1 Piping
14. Class 1 Piping Leak-Before-Break Analyses
15. Containment Tendon Loss of Prestress Analysis
16. Containment Liner Plate Fatigue Analysis
17. Crane Load Cycle Limit
18. Environmental Qualification of Electrical Equipment
19. Spent Fuel Pool Boraflex
20. Spent Fuel Pool Liner
21. Vessel and Piping Subsurface Indications

4.1.1.2 TLAA Current Licensing Basis (CLB) Document Search

The Current Licensing Basis (CLB) documents were searched to determine if any potential TLAAs not previously identified by the industry may exist for Point Beach Nuclear Plant (PBNP).

Methodology

The following documents were searched electronically for typical keywords which are indicative of a discussion of a TLAA:

- FSAR
- Technical Specification
- NRC Safety Evaluation Reports (SERs)
- Docketed Correspondence
- NRC Regulatory Commitments and Requirements

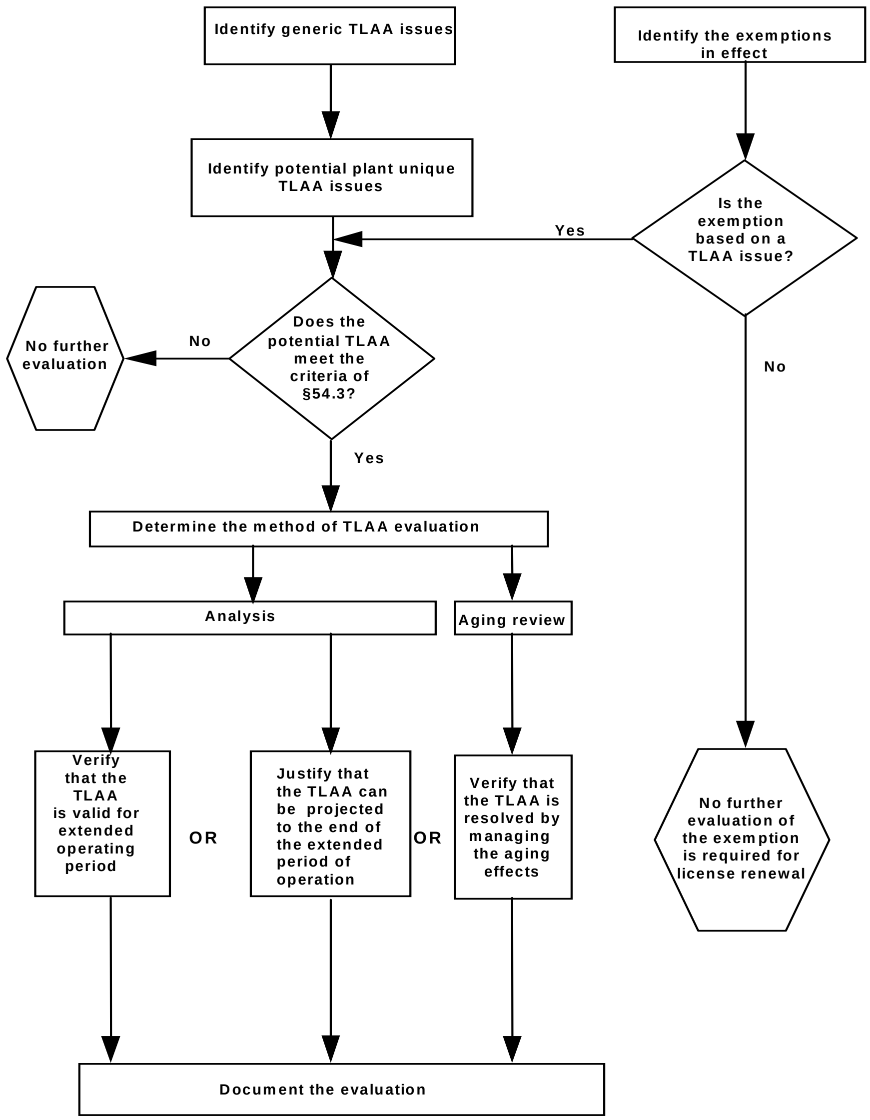
In addition, Aging Management Review evaluations also included consideration for identifying the existence of potential TLAAs.

Each document identified in the above activities as containing a potential TLAA was reviewed to determine if it was in fact a TLAA for PBNP. The plant specific TLAAs were then compared to those potential TLAAs identified through the Industry related search.

Plant Specific Results

The TLAAs identified through the PBNP specific electronic CLB searches, and the AMR evaluation(s) were previously identified as potential TLAAs through the industry related search. These searches did not reveal any new TLAAs.

Figure 4.1-1 TLAA Methodology



4.1.2 Identification of Exemptions

The requirements of 10 CFR 54.21(c) stipulate that the application for a renewed license should include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12, and that are in effect, based on time-limited aging analyses, as defined in 10 CFR 54.3.

Active 10 CFR 50.12 exemptions were reviewed to determine whether the exemption was based on a time-limited aging analysis.

Master Curve Related Exemptions

In accordance with the provisions of 10 CFR 50.12, “Specific Exemptions,” PBNP submitted a request for permanent exemption from certain requirements of 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Thermal Shock Events,” 10 CFR 50, Appendix G, “Fracture Toughness Requirements,” and 10 CFR 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements,” for the Unit 2 reactor vessel dated September 26, 2003 (Reference 62).

The requested exemptions would allow use of a different method, the Master Curve Methodology, for determining the adjusted RT_{NDT} (reference nil-ductility temperature) of the Point Beach Nuclear Plant Unit 2 (PBNP Unit 2) reactor vessel limiting circumferential weld metal. This method is used for the Pressurized Thermal Shock (PTS) screening evaluation.

The three exemptions requested by PBNP address portions of the following regulations:

1. Appendix G to 10 CFR 50, which sets forth fracture toughness requirements for ferritic materials of pressure-retaining components of the reactor coolant pressure boundary of light water nuclear power reactors to provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the system may be subjected over its service lifetime;
2. 10 CFR 50.61, which sets forth fracture toughness requirements for protection against pressurized thermal shock (PTS); and
3. Appendix H to 10 CFR 50, which requires the establishment of a RPV material surveillance program.

The exemption from Appendix G to 10 CFR 50 is to replace the required use of the existing Charpy V-notch and drop-weight-based methodology and allow the use of an alternate methodology to incorporate the use of fracture toughness test data for evaluating the integrity of the PBNP Unit 2 circumferential beltline weld based on use of the 2002 Edition of American Society for Testing and Materials (ASTM) Standard Method E 1921 (E 1921-02) and American Society for Mechanical Engineering (ASME) Code Case N-629, and N-631. The exemption is required since Appendix G to Section XI of the ASME Code pursuant to 10

CFR 50.55(a) requires the use of a methodology based on Charpy V-notch and drop weight data.

The exemption from 10 CFR 50.61 is to use an alternate methodology to allow the use of fracture toughness test data for evaluating the integrity of the PBNP Unit 2 limiting circumferential beltline weld based on the use of ASTM E 1921-02 and ASME Code Case N-629. The exemption is required because the methodology for evaluating RPV material fracture toughness in 10 CFR 50.61 requires the use of Charpy V-notch and drop weight data for establishing the PTS reference temperature (RT_{PTS}).

Finally, the exemption from Appendix H to 10 CFR 50 is to modify the basis for the PBNP Unit 2 surveillance program to allow the acquisition and use of fracture toughness data instead of the Charpy V-notch impact testing required by Appendix H to 10 CFR 50. The exemption is required because Appendix H to 10 CFR 50 does not address the testing of surveillance specimens for direct measurement of fracture toughness. A second reason for the exemption relates to a supplemental surveillance capsule. Due to the need for additional fracture toughness data for the PBNP Unit 2 weld metal at fluence levels extending out to EOLE, a supplemental capsule has been added to the surveillance program for PBNP Unit 2. This capsule has been installed in the highest lead factor location and includes other RPV beltline materials. The capsule is designed for Master Curve fracture toughness testing and evaluation at the projected EOLE fluence, so that the integrity of the RPV will be directly validated with the testing of this capsule should extended operation be considered. The composition of materials, specimen types, and estimated schedule for removal of this new capsule are addressed in ATI Consulting Report 021-030-2003-1.

A tabular summary of the requested exemptions and the proposed alternatives are shown in Table 4.1-1 below. No other plant-specific exemptions granted pursuant to 10 CFR 50.12, and based on a time-limited aging analysis as defined in 10 CFR 54.3 were identified.

Table 4.1-1 Active Exemptions Associated with Time-Limited Aging Analyses

Exemption Description	Existing Requirement	Alternative Used	Date Granted / Associated TLAA
Exemptions Applicable to Master Curve			
Determination of adjusted/indexing reference temperatures	10 CFR 50.61 and Appendix G to 10 CFR 50	ASME Code Case N-629, ASME Code Case N-631, ATI Consulting Report 021-030-2003-1, BAW-2308, Revision 1, and Framatome ANP Calculation 32-5019743-01.	Submitted / Pressurized Thermal Shock
Use of the latest edition of supplemental ASTM E185-98	App H to 10 CFR 50 specifies use of ASTM E185-73, -79, -82 for testing of surveillance materials	(1) ASTM E185-98 allows use of ASTM E1921-02 for testing of surveillance capsule material; (2) Use fracture toughness surveillance data from PBNP Unit 2 surveillance capsule for verification of EOLE toughness properties. Capsule withdrawal will be managed by the Reactor Vessel Surveillance Program.	Submitted / Pressurized Thermal Shock
Alternative testing methods for determination of fracture toughness	Appendices G and H to 10 CFR 50 specifies Charpy V-Notch impact and drop weight testing	ASTM E1921-02, ATI Consulting Report and 021-030-2003-1.	Submitted / Pressurized Thermal Shock

4.1.3 Evaluation Process of Time-Limited Aging Analyses

Each potential TLAA identified in Section 4.1.1 was screened against the 6 criteria of 10 CFR 54.3(a). Once a TLAA was identified as applicable to PBNP, an evaluation was performed, as required by 10 CFR 54.21(c)(1), to demonstrate that at least one of the following criteria was applicable:

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.

iii. The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The results of these evaluations are provided in Table 4.1-2 and are discussed in Section 4.2 through Section 4.8.

Table 4.1-2 Time Limited Aging Analyses

TLAA Category	Number	TLAA	Section	Disposition 10 CFR 54.21(c)(1)	Comments
Reactor Vessel Irradiation Embrittlement	1	Reactor Vessel Pressurized Thermal Shock	4.2.1	(ii) projected to the end of the period of extended operation	
	2	Reactor Vessel Upper-Shelf Energy	4.2.2	(ii) projected to the end of the period of extended operation	
	3	Reactor Vessel Pressure/ Temperature Limits	4.2.3	(ii) projected to the end of the period of extended operation	Includes LTOP setpoint calculation(s)
Fatigue	4	Reactor Vessel Structural Integrity	4.3.1	(ii) projected to the end of the period of extended operation	
	5	Reactor Vessel Internals Structural Integrity	4.3.2	(ii) projected to the end of the period of extended operation	
	6	Control Rod Drive Mechanism Structural Integrity	4.3.3	(ii) projected to the end of the period of extended operation	
	7	Steam Generator Structural Integrity	4.3.4	(ii) projected to the end of the period of extended operation & (iii) effects of aging on the intended function will be adequately managed for the period of extended operation	The Unit 1 SGs' inspection port closure bolting replacement will be managed for the extended period of operation.by the Periodic Surveillance and Preventive Maintenance Program
	8	Pressurizer Structural Integrity	4.3.5	(ii) projected to the end of the period of extended operation	

Table 4.1-2 Time Limited Aging Analyses

TLAA Category	Number	TLAA	Section	Disposition 10 CFR 54.21(c)(1)	Comments
Fatigue	9	Reactor Coolant Pump Structural Integrity	4.3.6	(ii) projected to the end of the period of extended operation	
	10	Pressurizer Surge Line Structural Integrity	4.3.7	(ii) projected to the end of the period of extended operation	
	11	Spray Header Piping Structural Integrity	4.3.8	(ii) projected to the end of the period of extended operation	
	12	USAS B31.1 Piping Structural Integrity	4.3.9	(i) remains valid for the period of extended operation	
	13	Environmental Effects on Fatigue	4.3.10	N/A	Not a TLAA for PBNP. However, an evaluation of NURGEG/CR-6260 locations are included in the LRA TLAA Section.
	14	Containment Liner Plate Fatigue Analysis	4.3.11	(i) remains valid for the period of extended operation	
	15	Spent Fuel Pool Liner Fatigue Analysis	4.3.12	N/A	Not a TLAA for PBNP. There is no Spent Fuel Pool Fatigue Analysis for PBNP.
	16	Crane Load Cycle Limit	4.3.13	(i) remains valid for the period of extended operation	Applicable only to NUREG-0612 cranes.

Table 4.1-2 Time Limited Aging Analyses

TLAA Category	Number	TLAA	Section	Disposition 10 CFR 54.21(c)(1)	Comments
Fracture Mechanics Analysis	17	Reactor Vessel Underclad Cracking	4.4.1	N/A	The degradation mechanism is not applicable to the PBNP vessels due to cladding technique. Thus, this issue is not a TLAA for PBNP.
	18	Reactor Coolant Pump Flywheel Analysis	4.4.2	(i) remains valid for the period of extended operation	
	19	Reactor Coolant Pump Casing Analysis (ASME Code Case N-481 Analysis)	4.4.3	(ii) projected to the end of the period of extended operation	The analysis to support ASME Code Case N-481 is not applicable to PBNP. The analysis was performed to demonstrate adequate fracture toughness for life extension, not for invoking ASME Code Case N-481.
	20	Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis	4.4.4	(ii) projected to the end of the period of extended operation	
	21	Pressurizer Surge Line Piping Leak-Before-Break Analysis	4.4.5	(i) remains valid for the period of extended operation	
	22	Class 1 Accumulator Injection Line Piping Leak-Before-Break Analysis	4.4.6	(i) remains valid for the period of extended operation	

Table 4.1-2 Time Limited Aging Analyses

TLAA Category	Number	TLAA	Section	Disposition 10 CFR 54.21(c)(1)	Comments
Fracture Mechanics Analysis	23	Class 1 RHR Line Piping Leak-Before-Break Analysis	4.4.7	(i) remains valid for the period of extended operation	
	24	Component/Piping Subsurface Indication Analysis	4.4.8	N/A	Not a TLAA for PBNP. No piping or component flaws exist at PBNP that are in excess of ASME Code allowables.
Loss of Preload	25	Containment Tendon Loss of Prestress Analysis	4.5.1	(ii) projected to the end of the period of extended operation	A confirmatory program is in place to monitor Containment Tendon prestress.
Neutron Absorber	26	Spent Fuel Pool Storage Rack Boraflex	4.6.1	(iii) effects of aging on the intended function will be adequately managed for the period of extended operation	
Wear	27	Bottom Mounted Instrumentation Thimble Tube Wear	4.7.1	N/A	Not a TLAA for PBNP.
	28	Containment Accident Recirculation Hx Tube Wear	4.7.2	N/A	Not a TLAA for PBNP. There is no tube wear analysis for PBNP.
Environmental Qualification	29	Environmental Qualification of Electrical Equipment	4.8.1	(iii) effects of aging on the intended function will be adequately managed for the period of extended operation	

4.2 Reactor Vessel Irradiation Embrittlement

This group of time-limited aging analyses concerns the effect of irradiation embrittlement on the belt-line regions (adjacent to the reactor core) of the Point Beach Nuclear Plant Units 1 and 2 reactor vessels, and how this mechanism affects analyses that provide operating limits or address regulatory requirements. The calculations discussed in this section use predictions of the cumulative effects on the reactor vessels from irradiation embrittlement. The calculations are based on periodic assessment of the neutron fluence and resultant changes in the reactor vessel material fracture toughness.

The intermediate and lower shells, and welds that join them in the beltline region, of the reactor vessel are fabricated from low alloy steels. These ferritic steels exhibit a ductile-brittle transition that results in fracture toughness property changes as a function of both temperature and irradiation. The material property of particular importance in assessing reactor vessel integrity is fracture toughness, which can be defined as the capability of a material to resist sudden failure caused by crack propagation. Fracture toughness is reduced by neutron irradiation. The measure of fracture toughness of the reactor vessel materials when the reactor vessel is above the brittle fracture / ductile failure transition temperature is referred to as upper-shelf energy. Upper-shelf energy is related to the ability of a material to resist ductile tearing. In addition, the temperature at which the brittle fracture / ductile failure transition occurs increases with increasing radiation. This shift in the transition temperature is referred to as the shift in reference nil ductility transition temperature (RT_{NDT}).

The effect of embrittlement due to neutron bombardment is evaluated for reactor vessel temperatures throughout the range of normal operating values. Heatup and cooldown curves consider normal, relatively slow thermal transients. Pressurized thermal shock transients are characterized by a rapid and significant decrease in reactor coolant temperature with high pressure in the reactor vessel. The high reactor vessel thermal stresses, when combined with the pressure stresses, are assumed to initiate the propagation of a small flaw that is postulated to exist in the reactor vessel beltline. Postulated high pressures could cause propagation of the flaw through the reactor vessel wall.

The first step in addressing the TLAAs associated with neutron embrittlement is the projection of the neutron fluence that the critical vessel locations experience. The Westinghouse Radiation Engineering and Analysis Group performed PBNP reactor vessel fluence projections. These fluence projections were based on historical operational data, and forecasted uprated (1678 MWt) power conditions without the presence of Hafnium power suppression absorber rods, for the extended operating period. The results of the calculated peak fluence values at various azimuthal locations on the vessel clad / base metal interface are presented in Table 4.2-1. The evaluation used the ENDF/B-VI scattering cross-section data set. The calculated fluence projections were determined using methods consistent with

Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.”

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Table 4.2-1 Summary of the Calculated Peak RPV Neutron Fluence Values at 53 EFPY (10^{19} n/cm^2, E > 1.0 MeV)

Component Description	Surface[i]	1/4T[ii]	3/4T[ii]
PBNP Unit 1: 53 EFPY (End of License Extension)			
Nozzle Belt Forging (122P237)	0.42	0.28	0.13
Inter. Shell Plate (A9811-1)	5.26	3.56	1.63
Lower Shell Plate (C1423-1)	4.79	3.24	1.49
Nozzle Belt to Intermediate Shell Circ. Weld (8T1762)	0.42	0.28	0.13
Intermediate Shell Axial Weld - ID 27% (1P0815)	3.44	2.32	1.07
Intermediate Shell Axial Weld - OD 73% (1P0661)	3.44	2.32	1.07
Intermediate to Lower Shell Circ. Weld (71249)	4.91	3.32	1.52
Lower Shell Axial Weld (61782)	3.37	2.28	1.05
PBNP Unit 2: 53 EFPY (End of License Extension)			
Nozzle Belt Forging (123V352)	0.55	0.37	0.17
Inter. Shell Forging (123V500)	5.39	3.65	1.67

Table 4.2-1 Summary of the Calculated Peak RPV Neutron Fluence Values at 53 EFPY (10^{19} n/cm^2, E > 1.0 MeV)

Component Description	Surface[i]	1/4T[ii]	3/4T[ii]
Lower Shell Forging (122W195)	5.32	3.60	1.65
Nozzle Belt to Intermediate Shell Circ. Weld (21935)	0.55	0.37	0.17
Intermediate to Lower Shell Circ. Weld (72442)	5.09	3.46	1.58

i. These fluence values are the calculated fluence values considering the power uprate without hafnium suppression rods.
ii. Neutron attenuation per Reg. Guide 1.99, Rev. 2

In addition to the plant specific neutron exposure calculations, dosimetry sets from three (3) in-vessel and twenty (20) ex-vessel sensor sets irradiated at Unit 1 and four (4) in-vessel and twenty (20) ex-vessel sensor sets irradiated at Unit 2 were also re-analyzed using dosimetry evaluation methodologies that follow the guidance provided in Regulatory guide 1.190. The results of these dosimetry re-evaluations were then used to validate the calculational models that were applied in the plant specific neutron transport analysis of the PBNP RPVs.

The welds in the reactor vessel are basically the same material as the parts being joined and may be considered to be included in the preceding discussions. The chemistry differences between weld metal and base metal affect the material properties that are degraded by embrittlement; therefore, the welds are evaluated separately when considering the afore mentioned aging effect. The fracture toughness properties of the ferritic materials in the reactor coolant pressure boundary are determined in accordance with the NRC Standard Review Plan. The beltline material properties of the Point Beach Unit 1 and 2 reactor vessels are presented in Table 4.2-2. The chemistry factors were calculated using Regulatory Guide 1.99 Revision 2, Positions 1.1 and 2.1. Position 1.1 uses the tables from the Reg. Guide along with the best estimate copper and nickel weight percents. Position 2.1 uses the surveillance capsule data from all capsules withdrawn to date.

These fluence projections were used in the Pressurized Thermal Shock evaluation required by 10 CFR 50.61, and the RCS Pressure-Temperature (P-T) Operating Limits required by 10 CFR 50, Appendix G. The Upper Shelf Energy (USE) evaluation required by 10 CFR 50, Appendix G, used a fluence projection based on an uprated power condition of 1650 MWt with hafnium suppression rods.

Table 4.2-2 Summary of the Best Estimate Cu and Ni Weight Percent, Initial RT_{NDT} Values and Chemistry Factor values for the PBNP Unit 1 and 2 Reactor Vessel Materials

Material Description	wt.% Cu	wt.% Ni	Initial RT_{NDT}	CF
PBNP Unit 1				
Nozzle Belt Forging (122P237)	0.11	0.82	50°F	77°F
Inter. Shell Plate (A9811-1)	0.20	0.06	1°F	88°F/79.3°F[i]
Lower Shell Plate (C1423-1)	0.12	0.07	1°F	55.3°F/35.8°F[i]
Nozzle Belt to Intermediate Shell Circ. Weld (8T1762)	0.19	0.57	-5°F	152.4°F
Intermediate Shell Axial Weld -ID 27% (1P0815)	0.17	0.52	-5°F	138.2°F
Intermediate Shell Axial Weld - OD 73% (1P0661)	0.17	0.64	-5°F	157.6°F
Intermediate to Lower Shell Girth Weld (71249)	0.23	0.59	10°F	167.6°F
Lower Shell Axial Weld (61782)	0.23	0.52	-5°F	157.4°F/163.3°F[i]
PBNP Unit 2				
Nozzle Belt Forging (123V352)	0.11	0.73	40°F	76°F

Table 4.2-2 Summary of the Best Estimate Cu and Ni Weight Percent, Initial RT_{NDT} Values and Chemistry Factor values for the PBNP Unit 1 and 2 Reactor Vessel Materials

Material Description	wt.% Cu	wt.% Ni	Initial RT_{NDT}	CF
Inter. Shell Forging (123V500)	0.09	0.70	40°F	58°F
Lower Shell Forging (122W195)	0.05	0.72	40°F	31°F/43°F[i]
Nozzle Belt to Intermediate Shell Girth Weld (21935)	0.18	0.70	-56°F[ii]	170°F
Intermediate to Lower Shell Circ. Weld (72442)	0.26	0.60	-5°F	180°F

i. Per Regulatory Guide 1.99, Rev. 2, Position 2.1.
ii. Generic Value of RT_{NDT}.

The calculated fluences and RPV material properties noted above were used in the TLAA calculations associated with RPV neutron embrittlement.

In addition, changes in RPV material properties are verified through surveillance specimen irradiation and testing.

Westinghouse Electric Company developed the original surveillance program for the PBNP Units 1 and 2 RPVs. Although the original program was in accordance with ASTM E 185-66, subsequent testing has followed the latest version of ASTM E 185 that was been approved by the NRC, through ASTM E 185-82. A description of the surveillance program and the pre-irradiation mechanical properties of the reactor vessel materials are presented in WCAP-7513 for Unit 1 (Reference 57), and WCAP-7712 for Unit 2 (Reference 58). The original PBNP surveillance program consisted of six surveillance capsules in each Unit, attached to the outside of the reactor vessel internals thermal shield. Each capsule contained mechanical specimens, dosimetry, and thermal monitors. The mechanical specimens were fabricated from material representative of the PBNP RPVs.

To date, four surveillance capsules have been removed and tested from each Units RPV. One of the standby capsules has also been removed from each Units RPV, and is being stored at Point Beach. The final, originally installed standby capsule remains in each PBNP RPV.

The surveillance materials in the capsules of the PBNP Units 1 and 2, and other early plant specific Reactor Vessel Surveillance Programs (RVSPs) were not selected in accordance with ASTM E 185-82. Hence, the materials monitored by the RVSPs are not always the materials judged in 10CFR50 Appendix H, to most likely be the controlling beltline region materials with regard to irradiation embrittlement for the RPV for which the RVSP was designed. Consequently, the applicability of the data generated in the plant specific RVSP is limited. However, by combining the data developed from several RVSPs, it is possible to use data developed in a given RVSP for application at a different RPV, and also practical to develop a database to predict irradiation behavior of those welds for which there is no specific data. This does not preclude plant specific characterization should sufficient credible surveillance data become available.

Although the PBNP Units 1 and 2 specific surveillance program capsules contained mechanical specimens representative of the materials of the PBNP RPVs, the capsules did not contain materials representative of the PBNP RPVs limiting welds.

Since the actual heat of the limiting weld metal for either of the PBNP Units RPV is not in the respective Unit's surveillance program, participation in the B&W Owners Group (B&WOG) Master Integrated Reactor Vessel Surveillance Program (MIRVP) (Reference 59) allows access to irradiated surveillance data of the PBNP limiting RPV welds.

The MIRVP combines 16 separate plant specific RVSPs and provides for sharing of irradiation sites. It addresses requirements for acquiring irradiation data and the need to improve the quality and quantity of fracture toughness data to support operation of the participating plants.

The MIRVP correlates data from both power reactor surveillance monitoring and test reactor research programs. The principal sources of information are the power reactor surveillance efforts; which consists of three parts. The first part is the continuation of the plant-specific RVSPs that monitor the irradiation damage to selected materials, as originally planned and licensed. These capsules contain samples of weld metal, plate, forging, and heat-affected zone (HAZ) material from the vessel beltline, and neutron dosimetry and thermal monitors. This part of the program will continue to monitor the long-term effects of neutron irradiation on the reactor vessel materials.

The second part of the program consists of a series of specially designed supplementary weld metal surveillance capsules (SUPCAPS) to study the effects of irradiation on a number of weld metals. The welds were selected because they were anticipated to be highly sensitive to irradiation damage because of their chemical composition and low initial Charpy upper shelf energies. These capsules differ from regular plant-specific RVSP capsules in that they include the necessary specimens to obtain fracture toughness properties of individual weld metals. The capsules are located in the same irradiation holder tubes as the regular plant-specific capsules at Crystal River-3 and Davis Besse.

The third part of the MIRVP consists of higher fluence supplementary weld metal surveillance capsules (HUPCAPS) to obtain irradiated weld metal data (primarily fracture toughness properties) to satisfy the requirements 10 CFR 50, Appendices G and H, and 10 CFR 50.61 for the current license and license renewal of the plants in the MIRVP. Additional objectives are to (1) provide a capsule of Westinghouse design for correlation of irradiation data in the Westinghouse neutronic environment with the B&W 177-FA environment; (2) provide irradiation of reconstituted specimens to accelerate data gathering; and, (3) provide definitive information on the annealing response of this family of materials.

The PBNP Unit 1 remaining original plant-specific RVSP capsule contains SA-1263 weld material that is a surrogate for SA-1585 and SA-1650, but is not relevant to the PBNP Unit 1 RPV limiting weld materials. The limiting beltline welds for PBNP Unit 1 are SA-847 and SA-1101. SA-847 is covered by surrogate materials SA-1036 in Ginna, and SA-1135 in SUPCAPS. The SA-1101 material is in the Turkey Point Unit 3 RVSP and SA-1094, a surrogate for SA-1101, is in the Turkey Point Unit 4 RVSP. SA-1263 benefits Surry Units 1 and 2 and Oconee Unit 1. However, it is covered in the SUPCAPS and HUPCAPS, and no additional data is required for this weld material.

These MIRVP capsules contain several Charpy V-notch and compact fracture toughness specimens of the WF-847 & SA-1101 weld material. EOLE data currently exists for the SA-847 surrogate material SA-1036. Additionally, Capsule A2 will be removed at a target EOLE fluence of 3.7×10^{19} n/cm^2. This capsule will be removed in approximately 2008 and will be used in EOLE evaluations of the PBNP Unit 1 SA-847 material.

In addition, a new PBNP surveillance capsule has been installed in PBNP Unit 2 for the purpose of obtaining relevant fracture toughness data at the EOLE fluence. The new PBNP Unit 2 surveillance capsule contains surveillance specimens that will be used to directly measure the fracture toughness of the PBNP Unit1 weld material SA-1101. When removed and tested, this surveillance capsule will provide EOLE data for the SA-1101 weld material. The supplemental surveillance capsule for PBNP Unit 2 was installed following Cycle 25. Details regarding the specific contents of the supplemental capsule may be found in WCAP-15856.

The PBNP Unit 2 remaining original plant-specific RVSP capsule contains WF-193 weld material that is a surrogate for WF-112 and WF-154, but is not relevant to the PBNP Unit 2 RPV limiting weld materials. The limiting beltline weld for PBNP Unit 2 is SA-1484. HUPCAP

A3 provided data on SA-1484 weld material with a fluence of 1.7 x 10^{19} n/cm^2. The WF-67 weld was produced using the same weld wire (heat 72442) as the SA-1484 weld, and is well characterized in the SUPCAPS and HUPCAPS.

These MIRVP capsules contain several Charpy V-notch and compact fracture toughness specimens of the WF-67 weld material. Two of these capsules have a target fluence of 3.0 x 10^{19} n/cm^2, which is approximately the projected EOL fluence for PBNP Unit 2. Capsule A1 was scheduled for removal from Davis Besse in 2008. Capsule A4 in Crystal River 3 should be available at about this same time depending upon the actual operating schedule. The exact status for capsule A1 will depend upon a revised operation schedule at Davis Besse once the issues associated with the reactor vessel head are resolved. Since these two capsules are essentially redundant to each other, the loss of one would not affect the ability to produce Master Curve fracture toughness results applicable to the PBNP Unit 2 vessel. Capsule L2 in Davis Besse has a lower target fluence and thus has little relevance for the PBNP Unit 2 vessel. When any or all of these specimens are tested, the new results will be integrated with the existing data to further assess RPV integrity.

In addition, as stated previously, a new PBNP Unit 2 surveillance capsule has been installed in PBNP Unit 2 for the purpose of obtaining relevant fracture toughness data at the EOLE fluence. The new Unit 2 surveillance capsule contains surveillance specimens that will be used to directly measure the fracture toughness of the PBNP Unit 2 weld metal heat 72442, as well as weld and plate materials from PBNP Unit 1 RPV, and a weld for the Davis Besse RPV. The supplemental surveillance capsule for PBNP Unit 2 was installed following Cycle 25. Details regarding the specific contents of the supplemental capsule may be found in WCAP-15856 (Reference 60).

The target fluence for the PBNP Unit 2 supplemental surveillance capsule will correspond to the peak reactor vessel fluence at EOLE, for the limiting weld metal. Surveillance data obtained from this capsule will provide direct fracture toughness measurements for the limiting weld metal at EOLE fluence. The EOLE peak fluence estimate for the PBNP Unit 2 circumferential weld is 5.085 x 10^{19} n/cm^2 and considers the affects of hafnium removal and power uprate. The resulting data will provide direct evidence to demonstrate adequate reactor vessel fracture toughness throughout the license renewal term.

Based on the fuel management strategies and power uprates planned for PBNP Unit 2, the supplemental surveillance capsule should be removed and tested at just over 38 EFPY (representing an EOLE fluence for the capsule materials), which is anticipated to be achieved by April of 2022. However, as further reactor operation occurs, more refined vessel and capsule fluence estimates can be made and a more definitive capsule withdrawal schedule may be established.

To meet the intent of current regulations that use the CVN-based approach, PBNP recognizes that the currently completed fracture toughness testing allows only the projection of an RT_{PTS} value for EOL and EOLE fluences using the ASTM E 1921-02 transition temperature, T_o, and the ASME Code defined transition temperature, RT_{To}, based on T_o (Code Case N-629). To achieve full compliance for EOL and EOLE fluences, this same approach will be applied by performing Master Curve testing to measure T_o at higher fluence values. The testing of the supplemental capsule as part of a revised surveillance program will allow direct measurement of fracture toughness at the fluence corresponding to EOLE, thus eliminating the need to extrapolate using lower fluence data.

Current TLAA fracture toughness extrapolations will be confirmed by future fracture toughness surveillance testing of the new supplemental surveillance capsule inserted in PBNP Unit 2 and irradiated to the EOLE RPV fluence; future testing of additional B&W Owners Group integrated program capsules at intermediate fluences is also scheduled. The testing of the intermediate fluence capsules from B&W Owners Group program will confirm the extrapolation for EOL, and the testing of the new Unit 2 capsule will confirm the extrapolation to EOLE

There are three distinct time-limited aging analyses associated with Reactor Vessel Irradiation Embrittlement:

- Pressurized Thermal Shock evaluation required by 10 CFR 50.61.
- Upper Shelf Energy (USE) evaluation required by 10 CFR 50, Appendix G.
- RCS Pressure-Temperature (P-T) Operating Limits required by 10 CFR 50, Appendix G.

Each of these analysis is discussed separately below:

4.2.1 Reactor Vessel Pressurized Thermal Shock

A limiting condition on RPV integrity known as pressurized thermal shock (PTS) may occur during a severe system transient such as a loss-of-coolant accident (LOCA) or steam line break. Such transients may challenge the integrity of the RPV under the following conditions: severe overcooling of the inside surface of the vessel wall followed by high repressurization; significant degradation of vessel material toughness caused by radiation embrittlement; and the presence of a critical-size defect in the vessel wall.

In 1985, the NRC issued a formal rule on PTS, 10 CFR 50.61. It established the screening criteria for pressurized water reactor (PWR) vessel embrittlement as measured by the reference temperature termed RT_{PTS}. Screening criteria were set corresponding to EOL plant operation for beltline axial weld seams, forgings, and plates at 270^oF, and at 300^oF for beltline circumferential weld seams. All PWR vessels in the United States have been required to evaluate vessel embrittlement in accordance with these criteria through the end of plant operation.

The NRC amended its regulations for PWR plants to change the procedure for calculating radiation embrittlement RT_{PTS} values. The revised PTS Rule was published in the Federal Register, May 15, 1991 with an effective date of June 14, 1991, and later updated on December 19, 1995 with an effective date of July 29, 1996. These amendments made the procedure for calculating RT_{PTS} values consistent with the method given in Regulatory Guide 1.99, Revision 2.

Initial RPV TLAA analyses were performed at partial uprated power (1650 MWt) conditions to calculate RT_{PTS} at the inside surface of the reactor vessel for the belt line materials at the end of the period of extended operation. Based on these initial calculations, additional remedial measures were determined not to be required for the Unit 1 reactor vessel during the period of extended operation. The RT_{PTS} values for the beltline materials at the end of the extended operating period were calculated to be lower than the applicable screening criteria values established in 10 CFR 50.61. However, based on these initial calculations, additional remedial measures would be required for Unit 2 reactor vessel during the license renewal period. The RT_{PTS} values for the beltline materials at the end of extended operating period were projected to be higher than the applicable screening criteria of 300°F established in 10 CFR 50.61.

Additional analyses were performed which addressed pressurized thermal shock for the PBNP Unit 1 RPV. These analyses were performed at full uprated power conditions (1678 Mwt, without Hafnium absorber rods) for a 60-year operating period. RT_{PTS} values were calculated for the inside surface of the beltline region materials for the Unit 1 RPV using Charpy based fracture toughness evaluations in accordance with the methods of 10 CFR 50.61. The RT_{PTS} values for the beltline region materials at the end of the extended operating period were calculated to be lower than the applicable screening criteria values established in 10 CFR 50.61. The values are summarized in Table 4.2.1-1.

Table 4.2.1-1 Summary of Unit 1 Calculated RT_{PTS} Values RPV Inside Surface - 53 EFPY, Without Hafnium - Charpy Based Methodology

Component Description	Fluence Factor	ΔRT_{NDT}(°F)	RT_{PTS}(°F)
Nozzle Belt Forging (122P237)	0.75	57.34	141
Inter. Shell Plate (A9811-1)	1.41	111.39	169
Lower Shell Plate (C1423-1)	1.39	49.61	107
Nozzle Belt to Intermediate Shell Circ. Weld (8T1762)	0.75	113.49	177
Intermediate Shell Axial Weld - ID 27% (1P0815)	1.31	181.52	245
Intermediate to Lower Shell Circ. Weld (71249)	1.39	233.04	299
Lower Shell Axial Weld (61782)	1.31	213.7	257

Additional analyses (Reference 61) were performed which addressed pressurized thermal shock for the PBNP Unit 2 RPV. These analyses were performed at full uprated power conditions (1678 MWt, without Hafnium absorber rods) for a 60-year operating period. RT_{PTS} values were calculated for the inside surface of the beltline region materials for the Unit 2 RPV using Charpy based fracture toughness evaluations in accordance with the methods of 10 CFR 50.61. The RT_{PTS} values for the beltline region materials at the end of the extended operating period were calculated to be lower than the applicable screening criteria values established in 10 CFR 50.61, with the exception of the intermediate to lower shell circumferential weld. The values are summarized in Table 4.2.1-2.

Table 4.2.1-2 Summary of Unit 2 Calculated RT_{PTS} Values RPV Inside Surface - 53 EFPY, Without Hafnium - Charpy Based Methodology

Component Description	Fluence Factor	ΔRT_{NDT}(°F)	RT_{PTS}(°F)
Nozzle Belt Forging (123V352)	0.88	63.30	137
Inter. Shell Forging (123V500)	1.14	82.17	156
Lower Shell Forging (122W195)	1.14	60.53	118
Nozzle Belt to Intermediate Shell Circ. Weld (21935)	0.88	141.58	151
Intermediate to Lower Shell Circ. Weld (72442)	1.41	253.02	316

As shown in the above Table, the EOLE fluence yields an RT_{PTS} value of 316°F when using Charpy based methods for the limiting weld for a power uprate to 1678.0 MWt and removal of the hafnium power suppression assemblies. Therefore, to obtain extra margin relative to reaching EOLE, a bounding evaluation of Master Curve fracture toughness data was used to properly define a fracture toughness-based transition temperature (Reference 61). The additional fracture toughness testing and evaluation using the Master Curve approach provides a technically superior method for assessing radiation damage to the limiting PBNP-2 weld.

The ATI Consulting Report (Reference 61) provides the detailed technical analysis and basis for the Master Curve application at PBNP Unit 2. A general summary is presented here. It should be noted that the ATI Consulting Report included a PBNP Unit 2 specific calculation using the methodology of BAW-2308, Revision 0 (Reference 72). Since the NRC staff was in the process of reviewing BAW-2308, Revision 1 (Reference 73) for approval, the NRC staff requested that PBNP perform the calculation using the methodology of BAW-2308, Revision 1. A PBNP Unit 2 specific RT_{PTS} calculation was performed using the methodology of BAW-2308, Revision 1, and is documented in Framatome ANP Calculation 32-5019743-01, “PBNP Unit 2 Power Uprate PTS Evaluation 53 EFPY”, Revision 1, 08/19/2003 (Reference 74). The specific PBNP Unit 2 results from each version of BAW-2308 are essentially identical.

The PBNP Unit 2 RPV limiting weld metal heat 72442 was not included in the current surveillance program for PBNP Unit 2, but it was irradiated as part of the B&W Owners Group integrated surveillance program. The latest projections based on Charpy impact testing, when analyzed following NRC guidelines and rules, indicate that this weld will reach the PTS screening criterion limit before EOLE. Therefore, fracture toughness testing of other irradiated surveillance specimens (from two different welds fabricated using weld wire 72442) has been performed and analyzed using the Master Curve methodology following ASME Code Cases N-629 and N-631. The evaluation performed involves extrapolation to EOLE fluences and shows that the RPV limiting weld metal has more than adequate toughness for operation out to EOLE and beyond. These projections will be confirmed by additional testing of weld heat 72442 from the B&W Owners Group Master Integrated Reactor Vessel Materials Surveillance Program (MIRVP) prior to reaching the EOL fluence at PBNP Unit 2. A supplemental surveillance program has been designed at PBNP Unit 2 that includes the limiting weld metal for future evaluation using the Master Curve methodology. The testing of this supplemental capsule at a fluence corresponding to EOLE will confirm the toughness condition for the PBNP Unit 2 RPV weld at about 38 EFPY, which is well before the EOLE fluence is reached.

The following observations and conclusions are documented in the ATI Consulting Report for the PBNP Unit 2 limiting beltline weld metal:

Application of the Master Curve methodology for the PBNP Unit 2 weld metal requires extrapolation (from the three available surveillance irradiations) to the RPV EOLE fluence. The extrapolation can be performed following several different approaches. Three approaches were evaluated: (1) use of measured initial RT_{To} and adding Charpy shift; (2) use of measured initial RT_{To} and adding the shift in RT_{To} due to irradiation; and (3) use of the measured irradiated RT_{To} values directly without projection from zero fluence. Method 1 somewhat follows the current regulatory practice and is the most conservative. Method 2 was evaluated following the Kewaunee SE, and the resulting projections were substantially less than Method 1. Method 3 is the most accurate method, and the results obtained applying this direct measurement approach reveal that Method 2 is quite conservative. All methods show that the EOLE RT_{PTS} value is less than the PTS screening limit of 300^{o}F. The projections for RT_{PTS} at EOLE are presented in Table 4.2.1-3.

Table 4.2.1-3 Comparisons of Reference Temperature Methods and Results

Method of Analysis	Material and Margin Properties			Inside Surface ART= RT_{PTS} Determination		
	Initial RT_{NDT} or RT_{To} (°F)	CF (°F)	Margin (°F)	Fluence Factor	ΔRT_{NDT} (°F)	ART = RT_{PTS} (°F)
Current Regulation	-5	180	68.5	1.406	253.0	316
$RT_{To(U)}$ + ΔCVN + Margin (B&WOG)	-38	180	60.8	1.406	253.0	276
$RT_{To(U)}$ + ΔRT_{To} + Margin (NRC)	-38	163	60.5	1.406	229.5	252
Direct Use of Irr. RT_{To}	--	180	42.9	1.406	RT_{irr} = 185.6	229

The margin term was chosen depending upon the analysis approach discussed above. For Method 1, margin was based on three uncertainties: material variability based on a Monte Carlo study from BAW-2308 of weld heat 72442 non-irradiated data (σ_{MC} = 9.3°F), the uncertainty in determining T_0 from ASTM E 1921-02 (σ_{To} = 7.4°F), and the current regulatory value for weld metal Charpy shift (σ_{Δ} = 28°F); σ_{MC} and σ_{To} are combined to give a measure of the uncertainty in initial properties (σ_I = 11.9°F). Method 2 used the margin specified by the NRC in the Kewaunee SE, which used a larger σ_I (14°F) and the same σ_{Δ} of 28°F. Method 3 used a more complete uncertainty analysis: material variability (σ_{MC} = 9.3°F as above), determination of irradiated T_0 (σ_{To} = 10.7°F), Cu content (σ_{Cu} = 1.6-1.7°F), Ni content (σ_{Ni} = 4.1-4.2°F), irradiation temperature (σ_{Tirr} = 6.9-8.9°F), fluence ($\sigma_{\phi t}$ = 13.2-12.5°F), and fluence projection (σ_{Proj} = 1.0-1.6°F). Remaining consistent with industry practice, an approximate 95% statistical level (or two sigma) margin was chosen, where the individual uncertainties were combined as two times the square root sum of the squares.

Since there was a need to extrapolate to higher fluence levels (higher than where current fracture toughness measurements exist) to assess PTS and pressure-temperature operating curves, the current Regulatory fluence function for CVN-based predictions was used for the Master Curve approach.

The supplemental surveillance program utilizes irradiation of the limiting weld metal heat in a new capsule that will be available for testing near the time corresponding to 38 EFPY for the RPV. The direct measurement of fracture toughness for key weld metal will be evaluated at a fluence near to the projected EOLE. Fracture toughness data from the B&W Owners Group on this same weld metal will be available around 2008. This B&W Owners Group data should correspond closely to the PBNP Unit 2 EOL fluence for the limiting RPV weld.

Use of the Master Curve methodology, extrapolated to EOLE fluence, shows that the RPV limiting weld metal meets PTS screening criteria out to EOLE and beyond. These projections will be confirmed by additional testing of weld heat 72442 from the B&W Owners Group MIRVP prior to reaching the EOL fluence at PBNP Unit 2. A supplemental surveillance program will be designed and implemented at PBNP Unit 2 that includes the limiting weld metal for future evaluation using the Master Curve methodology. The testing of this supplemental capsule at a fluence corresponding to EOLE will confirm the toughness condition for the PBNP Unit 2 RPV weld at about 38 EFPY, which is well before EOLE is reached.

To allow the use of the Master Curve Methodology, for determining the adjusted RT_{NDT} (reference nil-ductility temperature) of the PBNP Unit 2 RPV limiting circumferential weld metal, PBNP submitted a request (Reference 62) for permanent exemption from certain requirements of 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Thermal Shock Events”, 10 CFR 50, Appendix G, “Fracture Toughness Requirements”, and 10 CFR 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements”, for the Unit 2 reactor vessel, in accordance with the provisions of 10 CFR 50.12, “Specific Exemptions.” This exemption request contains calculations of RT_{PTS} values for the Point Beach Unit 2 reactor vessel beltline materials using the measured initial RT_{To} and adding a Charpy shift (Method 1 described in the preceding section). This exemption request, and supporting calculations, demonstrates that the limiting reactor vessel beltline material will remain below the 10 CFR 50.61 screening criteria during the end-of-life extension period (53 EFPY, power uprate to 1678.0 MWt, and removal of the hafnium power suppression assemblies). This method is used for the Pressurized Thermal Shock (PTS) screening evaluation.

The three exemptions requested by PBNP address portions of the following regulations:

Appendix G to 10 CFR 50, which sets forth fracture toughness requirements for ferritic materials of pressure-retaining components of the reactor coolant pressure boundary of light water nuclear power reactors to provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the system may be subjected over its service lifetime; 10 CFR 50.61, which sets forth fracture toughness requirements for protection against pressurized thermal shock (PTS); and Appendix H to 10 CFR 50, which requires the establishment of a RPV material surveillance program.

The exemption from Appendix G to 10 CFR 50 is to replace the required use of the existing Charpy V-notch and drop-weight-based methodology and allow the use of an alternate methodology to incorporate the use of fracture toughness test data for evaluating the integrity of the PBNP Unit 2 circumferential beltline weld based on use of the 2002 Edition of American Society for Testing and Materials (ASTM) Standard Method E 1921 (E 1921-02) and American Society for Mechanical Engineering (ASME) Code Case N-629 and N-631. The exemption is required since Appendix G to Section XI of the ASME Code pursuant to 10 CFR 50.55(a) requires the use of a methodology based on Charpy V-notch and drop weight data.

The exemption from 10 CFR 50.61 is to use an alternate methodology to allow the use of fracture toughness test data for evaluating the integrity of the PBNP Unit 2 limiting circumferential beltline weld based on the use of ASTM E 1921-02 and ASME Code Case N-629. The exemption is required because the methodology for evaluating RPV material fracture toughness in 10 CFR 50.61 requires the use of Charpy V-notch and drop weight data for establishing the PTS reference temperature (RT_{PTS}).

Finally, the exemption from Appendix H to 10 CFR 50 is to modify the basis for the PBNP Unit 2 surveillance program to allow the acquisition and use of fracture toughness data instead of the Charpy V-notch impact testing required by Appendix H to 10 CFR 50. The exemption is required because Appendix H to 10 CFR 50 does not address the testing of surveillance specimens for direct measurement of fracture toughness. A second reason for the exemption relates to a supplemental surveillance capsule. Due to the need for additional fracture toughness data for the PBNP Unit 2 weld metal at fluence levels extending out to EOLE, a supplemental capsule has been added to the surveillance program for PBNP Unit 2. This capsule has been installed in the highest lead factor location and includes other RPV beltline materials. The capsule is designed for Master Curve fracture toughness testing and evaluation at the projected EOLE fluence, so that the integrity of the RPV will be directly validated with the testing of this capsule should extended operation be considered. The composition of materials, specimen types, and estimated schedule for removal of this new capsule are addressed in the ATI Consulting Report.

The analysis associated with pressurized thermal shock has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.2 Reactor Vessel Upper Shelf Energy

The requirements on reactor vessel Charpy upper-shelf energy are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G requires licensees to submit an analysis at least 3 years prior to the time that the upper-shelf energy of any of the reactor vessel material is predicted to drop below 50 ft-lb., as measured by Charpy V-notch specimen testing. Limiting PBNP RPV weld materials fall below the 10 CFR 50, Appendix G, requirement of 50 ft-lb. Consequently, fracture mechanics evaluations were performed to demonstrate acceptable equivalent margins of safety against fracture.

A fracture mechanics evaluation has been performed to examine the PBNP upper shelf energy (USE) values in limiting welds at an uprated power condition of 1650 MWt with Hafnium suppression rods. This evaluation examined the USE values for both EOL as well as end of life extension (EOLE) conditions. The upper shelf energy data in the PBNP fracture mechanics evaluation is reported in J-R (J-Resistance) values with units of lb/in. Acceptability of these J-R values in satisfying the upper-shelf energy requirement is demonstrated by examining J-R ratios. This ratio is defined as the ratio of the lower bound J-R value divided by the applied J. If this ratio is greater than or equal to one, the acceptance criteria are met. The J-R ratio methodology is described in B&W Owners Reactor Vessel Working Group reports BAW-2178PA (Reference 63), “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level C & D Service Loads,” and BAW-2192PA (Reference 64), “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level A & B Service Loads,” both dated April 1994. The NRC staff reviewed and approved both of these reports for referencing in licensing applications in separate safety evaluations on March 29, 1994 (Reference 65 and Reference 66).

A plant specific fracture mechanics evaluation was performed and demonstrated acceptable equivalent margins of safety against fracture. This evaluation used the same methodologies described in the above references. The EOLE lower bounding J-R values and all acceptance ratios are summarized in Table 4.2.2-1.

Table 4.2.2-1 EOLE Lower Bounding J-R Values and Acceptance Ratios

Unit	Weld Number	Weld Orientation	Lower Bounding J-R (J_{01})(lb/in)	Acceptance Criterion 1		Acceptance Criterion 2	
				J_{app}(lb/in)	J_{01}/J_{app}	J_{app}(lb/in)	J_{01}/J_{app}
Unit 1	SA-1426	Circ.	685	105	6.52	121	5.66
	SA-1101	Circ.	582	105	5.54	121	4.81
	SA-812	Long.	678	319	2.13	372	1.82
	SA-847	Long.	602	319	1.89	372	1.62
Unit 2	SA-1092	Circ.	625	105	5.95	121	5.17
	SA-1484	Circ.	599	105	5.70	121	4.95

The minimum lower bounding J-R value at EOLE is 582 lb/in, which is at the Unit 1 RPV circumferential weld SA-1101.The minimum ratio of material J-R to applied J for acceptance criterion 1 and 2 at EOLE, is 1.89 and 1.62 respectively. The controlling weld is the Unit 1 RPV longitudinal weld SA-847. Since the values of the J-R ratios are greater than one, the acceptance criteria for the equivalent margins analysis have been met.

For consistency in application of the fluence projections in the reactor vessel irradiation embrittlement related TLAA evaluations, the upper shelf energy evaluation will be revised prior to entering into the extended period of operation. A revised fracture mechanics evaluation will be performed to examine the PBNP upper shelf energy (USE) values in the limiting welds at an uprated power condition of 1678 MWt, without hafnium power suppression absorber rods installed, for end of life extension (EOLE) conditions

The analysis associated with upper-shelf energy has been projected to the end of the period of extended operation, at a partially uprated power condition (1650 MWt) with hafnium suppression assemblies installed, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.3 Reactor Vessel Pressure/Temperature Limits

Atomic Energy Commission (AEC) General Design Criterion (GDC) 14 of 10 CFR 50, Appendix A, “Reactor Coolant Pressure Boundary,” requires that the reactor coolant pressure boundary be designed, fabricated, erected, and tested to have an extremely low probability of abnormal leakage or rapid failure and of gross rupture. Likewise, GDC 31, “Fracture Prevention of Reactor Coolant Pressure Boundary,” requires that the reactor coolant pressure boundary be designed with sufficient margin to reasonably assure that when stressed by operation, maintenance, and testing conditions, the boundary behaves in a non-brittle manner and the probability of rapidly propagating fracture is minimized. GDC 32, “Inspection of Reactor Coolant Pressure Boundary,” requires an appropriate materials surveillance program for assessing the structural integrity of the reactor vessel's beltline region.

Heatup and cooldown limit curves are calculated using the adjusted RT_{NDT} (reference nil-ductility temperature) corresponding to the limiting beltline region material of the reactor vessel. The adjusted RT_{NDT} of the limiting material in the core region of the reactor vessel is determined by using the unirradiated reactor vessel material fracture toughness properties, estimating the radiation-induced ΔRT_{NDT}, and adding a margin. The unirradiated RT_{NDT} is designated as the higher of either the drop weight nil-ductility transition temperature (NDTT) or the temperature at which the material exhibits at least 50 ft-lb of impact energy and 35-mil lateral expansion (normal to the major working direction) minus 60°F.

RT_{NDT} increases as the material is exposed to fast-neutron radiation. Therefore, to find the most limiting RT_{NDT} at any time period in the reactor's life, ΔRT_{NDT} due to the radiation exposure associated with that time period must be added to the unirradiated RT_{NDT} (IRT_{NDT}). The extent of the shift in RT_{NDT} is enhanced by certain chemical elements (such as copper and nickel) present in reactor vessel steels. The Nuclear Regulatory Commission (NRC) has published a method for predicting irradiation embrittlement in Regulatory Guide 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials”. Regulatory Guide 1.99, Revision 2, is used for the calculation of Adjusted Reference Temperature (ART) values (IRT_{NDT} + ΔRT_{NDT} + margins for uncertainties) at the 1/4T and 3/4T locations, where T is the thickness of the vessel at the beltline region measured from the clad/base metal interface.

New heatup and cooldown pressure temperature (PT) limit curves have been developed for PBNP Units 1 and 2. The PT curves were generated for EOL and EOLE operating periods based on the latest available reactor vessel information and calculated fluence projections that included the impact of the power uprating (1678 MWt) including removal of the Hafnium absorber rods.

The heatup and cooldown curves were generated using the most limiting ART values and the NRC approved methodology documented in WCAP-14040-NP-A, Revision 2, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves” (Reference 67) with the exception of the following: 1) The fluence values used in this report are calculated fluence values (i.e. comply with Reg. Guide 1.190), not the best estimate fluence values; 2) The K_{Ic} critical stress intensities are used in place of the K_{Ia} critical stress intensities. This methodology is taken from approved ASME Code Case N-641 (which covers Code Cases N-640 and N-588); 3) The 1996 Version of Appendix G to Section XI will be used rather than the 1989 version; and 4) PT

Curves were generated with the most limiting circumferential weld ART value in conjunction with Code Case N-588. These curves are bounded by the curves using the standard “axial” flaw methodology from ASME Code 1996 App. G with the ART from the intermediate or lower shell axial welds depending of the flaw location, 1/4T versus 3/4T. The Master Curve methodology has been incorporated in the analysis for determining the adjusted reference nil-ductility temperature for the PBNP Unit 2 lower circumferential weld material.

Master Curve fracture toughness testing has been performed on the PBNP Unit 2 girth weld metal (Reference 61). The results from this testing on weld wire heat 72442 are being incorporated into the determination of heatup and cooldown pressure-temperature (P-T) curves for the PBNP Unit 2 RPV. The approach taken using Master Curve data utilizes the projected values of RT_{To} at EOLE maximum fluence levels for the girth weld to determine the value of adjusted reference temperature (ART). ART is the regulatory index value for use of the ASME Code reference fracture toughness curves. The methodology used for determining ART follows the approach that was the basis for the Kewaunee safety evaluation (SE) for the limiting girth weld in the Kewaunee RPV (Reference 68).

The calculation of heat-up and cool-down curves requires ART values at the 1/4-thickness (1/4T) and 3/4-thickness (3/4T) through wall locations corresponding to the peak fluence for the girth (circumferential) weld. The attenuation of fluence through the wall of the RPV was determined using the method in Regulatory Guide 1.99, Rev. 2 and the optional method in ASTM E 900-02, which relies on an exponential decrease through the RPV wall. This attenuation formula for fluence is based upon DBA rather than neutron fluence with E > 1 MeV, and is applied for determining the fluences at 1/4T and 3/4T in the 6.5-in PBNP-2 RPV. The ART values are then calculated using the Method 2 approach presented in Reference 4, which follows the NRC evaluation method for the Kewaunee RPV. Table 4.2.3-1 lists the results of these calculations for the 1/4T location at EOLE, and Table 4.2.3-2 lists the 3/4T location results for EOLE. The three rows in each of the tables are the projected calculations corresponding to the measured values of RT_{To} from the specific capsules. Chemistry, temperature, and fluence differences between the capsule results are adjusted to reflect the RPV weld. The average of the three calculations at the end of each table is the ART value used for the P-T curve determination representing the girth weld metal in the PBNP-2 RPV.

Table 4.2.3-1 NRC Method (Reference 69) for Determining ART at 1/4T for EOLE Fluence

Material &Capsule	Chemistry and Temperature Adjusted ΔRT_{To} (^oF)	Fluence Function Ratio[i]	Total Adjusted ΔRT_{To} (^oF)	Adjusted RT_{irr} (^oF)	Margin[ii] (^oF)	ART (^oF)
SA-1484/A3	210.7	1.245	262.4	223.4	60.5	283.9
WF-67/L1	149.8	1.244	186.4	150.4	60.5	210.9
WF-67/LG2	170.3	1.161	197.7	161.7	60.5	222.2
					Average	**239**

i. Ratio of the fluence functions between the RPV at EOLE and the surveillance capsule
ii. The margin established by NRC in the Kewaunee SE (Margin = 2 $[(14)^2 + (28)^2]^{1/2}$ - 2)

Table 4.2.3-2 NRC Method (Reference 69) for Determining ART at 3/4T for EOLE Fluence

Material & Capsule	Chemistry and Temperature Adjusted ΔRT_{To} (^oF)	Fluence Function Ratio[i]	Total Adjusted ΔRT_{To} (^oF)	Adjusted RT_{irr} (^oF)	Margin[ii] (^oF)	ART (^oF)
SA-1484/A3	210.7	1.060	223.4	184.4	60.5	244.9
WF-67/L1	149.8	1.059	158.7	122.7	60.5	183.2
WF-67/LG2	170.3	0.988	168.3	132.3	60.5	192.8
					Average	**207**

i. Ratio of the fluence functions between the RPV at EOLE and the surveillance capsule
ii. The margin established by NRC in the Kewaunee SE (Margin = 2 $[(14)^2 + (28)^2]^{1/2}$ - 2)

Contained in Table 4.2.3-3 is a summary of the limiting ARTs used in the generation of the PBNP Units 1 and 2 PT limit curves. When considering the master-curve ART for the Unit 2 intermediate to lower shell girth weld, the highest “Circ-Flaw” ART would then come from the PBNP Unit 1 intermediate to lower shell circumferential weld. The most limiting “Axial-Flaw” ART comes from the PBNP Unit 1 lower shell axial welds (for 1/4T) and the intermediate shell axial welds (for 3/4T)

Table 4.2.3-3 Summary of the Limiting ART Values Used in the Generation of the PBNP Units 1 and 2 Heatup/Cooldown Curves

EFPY	Limiting "Circ-Flaw" ART [i]		Limiting "Axial-Flaw" ART (°F)	
	¼T(°F)	¾T (°F)	¼T(°F)	¾T (°F)
PBNP Unit 1[ii]				
53	286	254	243	224
PBNP Unit 2[iii]				
53	301 (239) [iv]	267 (207) [iv]	152	140

i. PBNP Units 1 and 2 Limiting Circ. Flaw ART comes from the Intermediate to lower shell circumferential welds (Heat #'s 71249 and 72442, respectively)
ii. The "Axial-Flaw" ARTs for PBNP Unit 1 are from the lower shell axial welds (1/4T) and the intermediate shell axial welds (3/4T)
iii. The "Axial-Flaw" ARTs for PBNP Unit 2 are from the intermediate shell forging 123V500.
iv. Values in parenthesis were calculated using Master-Curve Technology

The new PBNP Unit 1 and 2 heatup and cooldown pressure-temperature limit curves were generated using adjusted reference temperature (ART) values that bound both units. The highest ART values from the two units were from the Unit 1 and Unit 2 intermediate to lower shell girth welds, however the limiting materials are actually the intermediate and lower shell axial welds from Unit 1, depending on the vessel thickness (1/4T or 3/4T location). The axial welds become limiting over the girth weld through use of "circ-flaw" methodology from ASME Code Case N-588. This methodology is less restrictive than the standard "axial-flaw" methodology from the 1995 ASME Code, Section XI through the 1996 Addenda. In addition to the use of Code Case N-588, the PT curves also made use of ASME Code Case N-640, which allows the use of the K_{Ic} methodology. Both ASME Code Case N-588 and N-640 were joined together under ASME Code Case N-641.

It is noted that although the Master Curve toughness application for the PBNP Unit 2 limiting circumferential weld has been considered in the P/T curve evaluation, there is no effect on the resulting P/T curves since the limiting materials for these curves are the intermediate and lower shell axial welds from PBNP Unit 1.

The PT limit curves were generated for 34 EFPY (EOL) and 53 EFPY (EOLE) using heatup rates of 60 and 100°F/hr and cooldown rates of 0, 20, 40, 60 and 100°F/hr. The PT curves include a hydrostatic leak test limit curve from 2485 psig to 2000 psig, along with the pressure-temperature limits for the vessel flange region per the requirements of 10 CFR 50, Appendix G. (A copy of these PT limit curves were provided to the NRC in Reference 70.)

In addition, maximum allowable low-temperature, overpressure protection system (LTOPS) power-operated relief valve (PORV) lift setpoints have been developed for a maximum of 34 EFPY, the end of the current operating license period, and for a maximum of 53 EFPY, the end of the extended operating license period, based on the P-T limits applicable to the period of operation.

To allow the use of the Master Curve Methodology, for determining the adjusted RT_{NDT} (reference nil-ductility temperature) of the PBNP Unit 2 RPV limiting circumferential weld metal, PBNP submitted a request for permanent exemption from certain requirements of 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Thermal Shock Events”, 10 CFR 50, Appendix G, “Fracture Toughness Requirements”, and 10 CFR 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements”, for the Unit 2 reactor vessel, in accordance with the provisions of 10 CFR 50.12, “Specific Exemptions” (Reference 70).

PBNP withdrew and resubmitted to the NRC a request for permanent exemption from certain requirements as discussed above to allow the use of Master Curve Methodology for PBNP Unit 2. This resubmittal provided information using an NRC preferred approach to the analysis. (Reference 62).

The analysis associated with reactor vessel pressure-temperature limit curves has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3 Metal Fatigue

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as time limited aging analyses for the Point Beach Nuclear Plant. Specific components have been designed and analyzed considering transient cycle assumptions identified in vendor specifications and the PBNP FSAR.

In conjunction with revising the NSSS design transients for the Unit 2 Steam Generator Replacement Project (SGRP), and the Power Uprate Project (PUP), the NSSS design transients for both units were also evaluated for acceptability for a 60-year operating period. The number of NSSS transients actually experienced by the two units was identified. Based on historical transient occurrences, and current plant operational practices, the number of future NSSS transients was forecasted for a 60-year operating period. With few exceptions, the anticipated number of transients for a 60-year operating period was far less than the original design number of transients for a 40-year operating period.

The exceptions noted above comprise a set of pressure test transients that were included in some of the NSSS component Equipment Specifications. The pressure test transients forecasted for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The NSSS design transient set was revised to include an increased number of pressure test transients, sufficient for a 60-year operating period.

In addition, the NSSS transient set was also revised to increase the number of steady state random RCS pressure and temperature fluctuations to ensure adequate margin existed for a 60-year operating period.

The revised set of NSSS design transients were used in performing the detailed engineering evaluations in support of the Power Uprate Project.

Experience has shown, however, that actual plant operation is often very conservative with respect to the design transients. The use of actual operating history and transient monitoring data acquired by the FatiguePro™ Automatic Cycle Counting and Fatigue Monitoring System installed at Point Beach (Fatigue Monitoring Program) will allow quantification of the conservatism in the existing fatigue analysis and demonstrate that the design fatigue analyses will bound the extended period of operation. The PBNP Fatigue Monitoring Program is considered a confirmatory program, and is described in Appendix B.

4.3.1 **Reactor Vessel Structural Integrity**

The PBNP reactor vessels were designed, constructed, and analyzed to the requirements of their original Equipment Specifications, and Section III of the ASME Code (Reference 1 and Reference 2). The original design transient sets are contained in the original Equipment

Specifications. The original reactor vessel Code Stress Reports were performed by the reactor vessel manufactures.

In conjunction with revising the NSSS design transients for the Unit 2 Steam Generator Replacement Project (SGRP), and the Power Uprate Project (PUP), the NSSS design transients for both units were also evaluated for acceptability for a 60-year operating period. The number of NSSS transients actually experienced by the two units was identified. Based on historical transient occurrences, and current plant operational practices, the number of future NSSS transients was forecasted for a 60-year operating period. With few exceptions, the anticipated number of transients for a 60-year operating period was far less than the original design number of transients for a 40-year operating period.

The exceptions noted above comprise a set of pressure test transients that were included in some of the NSSS component Equipment Specifications. The pressure test transients forecasted for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The NSSS design transient set was revised to include an increased number of pressure test transients, sufficient for a 60-year operating period.

In addition, the NSSS transient set was also revised to increase the number of steady state random RCS pressure and temperature fluctuations to ensure adequate margin existed for a 60-year operating period.

The revised set of NSSS design transients were used in performing the detailed engineering evaluations in support of the Steam Generator Replacement Project, and the Power Uprate Project.

The revised NSSS operating conditions, NSSS design transients, and design loads affect several of the maximum ranges of stress intensity and fatigue usage factors reported in the original PBNP reactor vessel stress reports. Evaluations were initially performed for the various regions of the PBNP reactor vessels to determine the stress and fatigue usage effects of these revised parameters at partially uprated conditions (1650 MWt) with a 60-year operating period.

The evaluations assessed the effects of the design transients and NSSS design parameters on the most limiting locations with regard to ranges of stress intensity and fatigue usage factors in each of the regions as identified in the reactor vessel stress reports and addendum. The evaluations considered a worst case set of design parameters and design transients from among the high temperature / high pressure RCS conditions, the high temperature / low pressure RCS conditions, the low temperature / high pressure RCS conditions, the low temperature / low pressure RCS conditions, the original design basis, and the transient set modification for a 60-year operating period. In the cases where the revised transients were not bounded by the original analyses, or the transients were not included in the original analyses, appropriate revised maximum ranges of stress intensity and maximum usage factors were calculated. Otherwise, the original design basis stress analyses remained conservative, so no new calculations were necessary, and the maximum ranges of stress intensity and fatigue usage factors reported in the original stress reports continued to govern.

Originally, the design requirements for the head adapter plugs conformed to the requirements for blind flanges as given in the American National Standards Institute (ANSI) B31.7 code. Reconciliation of the revised NSSS transients with this code of construction would require no stress analysis since no structural welding is involved. Since the head adapter plug forms the primary pressure boundary along with the vessel, it is prudent to qualify the head adapter plugs to the same codes of construction as the vessels. Therefore, a fatigue and stress evaluation of the reactor vessel head adapter plug was performed. The design complies with the requirements of the Westinghouse Equipment Specifications, and the requirements of Section III of the ASME B&PV Code (1965 Edition for Unit 1 and 1968 Edition with addenda through Winter 1968 for Unit 2) for a 60-year operating period.

The reactor vessel stress and fatigue calculations were reanalyzed for the Power Uprate Project at full uprated conditions, including the revised transient set for a 60-year operating period. The structural evaluation concluded that all reactor vessel components analyzed for fatigue are within allowable limits for a 60-year operating period.

The evaluations demonstrated acceptable results in accordance with both the 1965 Edition of Section III of the ASME B&PV Code for the Unit 1 reactor vessel, and the 1968 Edition of Section III of the ASME B&PV Code with addenda through the Winter of 1968 for the Unit 2 reactor vessel for a 60-year operating period at a NSSS power level of 1684 MWt.

The PBNP RPV heads are scheduled for replacement in the 2005 and 2006 refueling outages. Westinghouse has been contracted to provide the replacement RPV heads. The replacement heads are currently being manufactured. The replacement heads will also include new CRDMs. Material and design enhancements are being incorporated into the replacement heads to enhance the corrosion resistance of the head penetration assemblies. Other design enhancements are being incorporated to aid in disassembly / assembly efficiency. Some of the enhancements include elimination of Alloy 600 materials, elimination of unnecessary spare head penetrations, elimination of unnecessary joints in the CRDM housings, and an improved penetration weld joint design. The replacement heads are being designed and manufactured to ASME Section III, 1998 edition thru 2000 Addendum. The design specification for the replacement RPV heads states that the components are designed to have a 40-year design life. The design specification for the replacement RPV heads specify the same design transient set that was used in the Steam Generator Replacement and Power Uprate Projects for EOLE conditions. Nevertheless, when the replacement components are placed into PBNP service, the 40-year design life is adequate to reach EOLE.

The analyses associated with verifying the structural integrity of the reactor vessels have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.2 Reactor Vessel Internals Structural Integrity

Since the Point Beach Units reactor vessel internals were designed prior to the introduction of Subsection NG of the ASME Boiler and Pressure Vessel Code Section III, a plant-specific stress report on the reactor vessel internals was not required for the original design. However, the design of the Point Beach Units reactor vessel internals was analyzed according to the Westinghouse internal criteria that were similar to the criteria described in Subsection NG of the ASME Code. Moreover, the structural integrity of the Point Beach Units reactor vessel internals design has been assured by analyses performed on both a generic and plant specific basis. These analyses were used as the basis for the evaluations of the critical Point Beach Nuclear Plant Units 1 and 2 reactor vessel internal components for uprated power conditions for a 60-year operating period.

In conjunction with revising the NSSS design transients for the Unit 2 Steam Generator Replacement Project (SGRP), and the Power Uprate Project (PUP), the NSSS design transients for both units were also evaluated for acceptability for a 60-year operating period. The number of NSSS transients actually experienced by the two units was identified. Based on historical transient occurrences, and current plant operational practices, the number of future NSSS transients was forecasted for a 60-year operating period. With few exceptions, the anticipated number of transients for a 60-year operating period was far less than the original design number of transients for a 40-year operating period.

The exceptions noted above comprise a set of pressure test transients that were included in some of the NSSS component Equipment Specifications. The pressure test transients forecasted for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The NSSS design transient set was revised to include an increased number of pressure test transients, sufficient for a 60-year operating period.

In addition, the NSSS transient set was also revised to increase the number of steady state random RCS pressure and temperature fluctuations to ensure adequate margin existed for a 60-year operating period.

The revised set of NSSS design transients were used in performing the detailed engineering evaluations in support of the Steam Generator Replacement Project, and the Power Uprate Project.

The reactor vessel internals fatigue analyses were initially reevaluated for the PBNP Steam Generator Replacement Project at partially uprated conditions (1650 MWt) with a 60-year operating period. Structural evaluations were performed to demonstrate that the structural integrity of the reactor vessel internals components were not adversely affected directly by the change in RCS conditions and transients and / or by secondary effects of the change on reactor thermal-hydraulic or structural performance. The presence of heat generated in reactor internal components, along with the various fluid temperatures, results in thermal gradients within and between components. These thermal gradients result in thermal stresses and thermal growth, which must be accounted for in the design and analysis of the various components.

Westinghouse performed a review and an evaluation of the effects of the revised NSSS design transients and the power uprate on the following key reactor internal components:

- Lower Core Plate
- Lower Core Support Plate
- Lower Support Columns
- Core Barrel Outlet Nozzle Projection
- Core Barrel Flange
- Lower Radial Restraints (Clevis Insert)
- Upper Core Plate Alignment Pin
- Upper Support Columns
- Upper Core Support Plate
- Upper Core Plate
- Guide Tubes and Support Pins
- Flexureless Insert

The results of this structural evaluation concluded that the change in RCS thermal transients due to uprated RCS conditions and a 60-year operating period does not significantly affect the stress and fatigue usage factors.

The reactor vessel internals fatigue analyses were reanalyzed for the Power Uprate Project at full uprated conditions (1684 MWt), including the revised transient set for a 60-year operating period. The structural evaluation concluded that all reactor vessel internals components analyzed for fatigue, using the methods of Subsection NG of the ASME B&PV Code, Section III, are within allowable limits for a 60-year operating period.

The analyses associated with verifying the structural integrity of the reactor vessel internals have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.3 Control Rod Drive Mechanism Structural Integrity

Both of the PBNP units have Westinghouse L-106A full length (F/L) Control Rod Drive Mechanisms (CRDM's). The original design of PBNP also included Royal Industries part length (P/L) CRDM's. The P/L CRDM's have been removed from Unit 1, however remain in place in Unit 2.

The F/L and P/L CRDMs were designed, constructed, and analyzed to the requirements of their original Equipment Specifications and Section III of the ASME Code. The original design transient sets are contained in the original Equipment Specifications. Generic code stress analyses were performed for the F/L and P/L CRDMs.

The projected number of NSSS design transients for a 60-year operating period is less than the original design value for a 40-year operating period, with the exception of hydrostatic pressure tests. The pressure test transients forecasted for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The NSSS design transient set was revised to increase the number of hydrostatic pressure test transients for the fatigue analysis performed to cover a 60-year operating period.

The Power Uprate Project evaluated the F/L and P/L CRDMs for uprated power conditions and a 60-year licensed operating period. The NSSS design parameters and the NSSS design transients were used to evaluate the impact of the uprate on the CRDMs. The fatigue analysis for the P/L CRDMs was determined to be bounded by the fatigue analysis for the F/L CRDMs.

The revised set of NSSS design transients developed for the power uprate conditions, including a 60-year operating period, were compared to the transients used in the F/L CRDM Equipment Specification and the associated generic code stress analysis. The Equipment Specification or the generic code stress analysis values bound the revised NSSS values except for the Large Step-Load Decrease, Loss of Load, Loss of Flow, and Reactor Trip transients. The revised power uprate NSS transient set also required consideration of Feedwater Cycling, Boron Concentration Equalization, Loss of Power, Inadvertent Actuation of Auxiliary Spray, Steam Line Break, and Turbine Roll Tests transients, that were not previously considered applicable to the PBNP CRDM's. These “new” transients were not previously considered applicable to the PBNP Units 1 and 2 CRDMs because they were not defined in the original equipment specification for the PBNP CRDMs. The transients that were not bounded, the “new” transients, and the additional hydrostatic test pressure transients were evaluated for their impact on fatigue.

Based on the above evaluations, and the previous generic code stress analyses, it was concluded that the design of the part-length and full-length CRDMs meets applicable ASME Code requirements at uprated NSSS power conditions for up to 60 years of operation.

The PBNP CRDMs are scheduled for replacement in the 2005 and 2006 refueling outages. Westinghouse has been contracted to provide the replacement CRDMs. The replacement CRDMs are currently being manufactured. Material and design enhancements are being incorporated into the replacement CRDMs to enhance the corrosion resistance of the CRDM assemblies. Some of the enhancements include elimination of Alloy 600 materials, elimination of unnecessary spare head penetrations, elimination of unnecessary joints in the CRDM housings, and an improved penetration weld joint design. The replacement heads are being designed and manufactured to ASME Section III, 1998 edition thru 2000 Addendum. The design specification for the replacement CRDMs states that the components are designed to have a 40-year design life. The design specification for the replacement CRDMs specify the same design transient set that was used in the Steam Generator Replacement and Power Uprate Projects for EOLE conditions. Nevertheless, when the replacement components are placed into PBNP service, the 40-year design life is adequate to reach EOLE.

The analyses associated with verifying the structural integrity of the PBNP P/L and F/L CRDM's have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.4 Steam Generator Structural Integrity

PBNP has replaced the steam generators in each unit. As a result, two different Westinghouse steam generator models are installed. Unit 1 has Model 44F steam generators and Unit 2 has Model Delta-47 steam generators. The Unit 1 steam generators were replaced in 1984, and the Unit 2 steam generators were replaced in 1996.

The projected number of steam generator design transients for a 60-year operating period are less than the original design value for a 40-year operating period, with the exception of hydrostatic pressure tests. The pressure test transients forecasted for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The design transient set was revised to increase the number of hydrostatic pressure test transients for the fatigue analysis performed to cover a 60-year operating period.

Both Units SGs were designed in accordance with the requirements of the ASME Section III Code. The Unit 1 replacement steam generators (44F) were designed with the original design transient set at the initial licensed core power level. The Unit 2 replacement steam generators (Delta-47) were designed with an augmented transient set at a partially uprated core power level.

The fatigue calculations were reanalyzed for the Unit 1 SGs (44F) at specified full uprating conditions (1678 MWt) with increased pressure test load cycles adequate for a 60-year operating period. The structural evaluation concluded that all steam generator components analyzed for fatigue are within the allowable limits for a 60-year operating period, with the exception of the Unit 1 inspection port bolts. The structural evaluation identifies a replacement interval of 12 years for the inspection port bolts. The Periodic Surveillance and Preventive Maintenance Program will manage the Unit 1 SG inspection port bolt replacement. This bolting replacement requirement will remain in place for the extended operating period.

The fatigue calculations were reanalyzed for the Unit 2 SGs (Delta-47) at full uprating conditions (1678 MWt) with increased pressure test load cycles. The structural evaluation concluded that all steam generator components analyzed for fatigue are within allowable limits for a 60-year operating period.

With the sole exception of the Unit 1 steam generator inspection port bolting, the analyses associated with verifying the structural integrity of the PBNP steam generators have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

The Periodic Surveillance and Preventative Maintenance Program will provide reasonable assurance that the Unit 1 SG inspection port bolt replacement is adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.5 Pressurizer Structural Integrity

Design Basis Code Fatigue Analysis for the Pressurizers

Fatigue in the pressurizer is produced by stresses due to mechanical and/or thermal loads. Some of the pressurizer components operate at high levels of both static and repeated stress and have high-calculated design fatigue usage, predominantly due to thermal environments during transient conditions. Pressurizers are subject to a wide variety of mechanical and thermal loads that contribute to fatigue accumulation. In the GTR, WCAP-14574-A, Westinghouse has identified that based on operating experience and a thorough review of existing analyses, the shell, spray nozzle, manway bolts, lower head, heater wells, surge nozzle, and support skirt and flange to be potential fatigue significant locations for extended operations.

The pressurizers were designed in accordance with the requirements of the ASME Section III Code for Class 1 vessels. Fatigue usage factors for critical locations in the PBNP pressurizers were initially evaluated using design transients that were specified early in the plant design process.

The projected number of design transients for a 60-year operating period are less than the original design value for a 40-year operating period, with the exception of hydrostatic pressure tests. The fatigue calculations were reanalyzed for the pressurizers at specified uprated power conditions with an increased number of hydrostatic pressure test load cycles, adequate for a 60-year operating period. The plant specific fatigue analysis results showed that the surge nozzle, spray nozzle, and upper head and shell have the highest fatigue cumulative usage factors (CUF), above 0.5. The results showed that the ASME Code limits were not exceeded for any of the pressurizer components.

Pressurizer In-surge/Out-surge

The industry discovered that thermal fatigue damage to the pressurizer lower head region was being experienced in excess of original design allowances due to apparent overcooling events. The overcooling events were the result of insurge/outsurge transients. Colder water from the hot leg entered the hotter pressurizer with a relative lack of mixing. The original design analysis assumed the colder water from the hot leg would mix in the bottom head of the pressurizer during an insurge transient. This, however, was not the case and resulted in additional fatigue usage for the pressurizer components in the lower head region.

The Westinghouse Owners group (WOG) commissioned a generic evaluation of the effects of this unanalyzed event. As a result:

- Modified Operating Procedures (MOP) were successfully tested and recommended for use in all plants to minimize or eliminate in-surge / out-surge cycling.
- Acceptable structural integrity of the pressurizer utilizing MOP methods was demonstrated for the CLB design life of the plant.
- Plant-specific structural integrity evaluations of the combined methods of operation were required to close the issue.

Point Beach has implemented the MOP methods to minimize the possibility of pressurizer overcooling events.

In addition, a PBNP plant specific insurge/outsurge fatigue analysis was performed to demonstrate adequate structural integrity for a projected 60-year operational period.

Three locations were selected for analysis:

- The pressurizer surge nozzle.
- The heater penetration well.
- The lower instrument nozzle.

These locations were determined to represent the bounding fatigue critical locations in the lower head region. The pressurizer surge nozzle is subjected to thermal shock in combination with thermal expansion piping loads, thermal stratification piping loads in the horizontal portion of the surge line, and pressure. The pressurizer heater tube and instrument penetrations are subjected to thermal shock and pressure.

The EPRI FatiguePro software program was customized to monitor fatigue-critical locations in the pressurizer's lower head at PBNP. An analysis was performed based on available template sets of real plant data to determine the incremental fatigue usage factor for known plant transients, including the effects of “insurge/outsurge.” Cumulative usage factors for the operating life of the plant were computed based on the results of real plant data, and expected future usage was computed using projections of expected plant cycles through EOLE.

The technical approach is summarized as follows:

- The flow rate in the surge line was computed based on a mass balance approach, using the incoming spray demand and the rate of change of the pressurizer water level, taking into account temperature effects.
- A 2-dimensional model was created to take into account (a) the advance and time delay of colder water from the hot leg into the surge line and lower head of the pressurizer, and (b) the heat transfer between the fluid and metal.
- This approach has been verified to be conservative based on available thermocouple data from another plant, as well as plant-specifically for PBNP by comparing the surge line temperature instrument reading with the FatiguePro calculated water temperature in the region of the surge nozzle. The temperatures at the nozzle and lower head are calculated in FatiguePro completely independently from the surge line temperature instrument.
- Finite element models (including thermal sleeves in the pressurizer surge nozzle and hot leg RCS surge nozzle) were created to compute “Green's Function” stress responses to step changes in temperature at various zones in the pressurizer. Stresses could then be computed based on the calculated fluid temperatures at the various zones in the pressurizer and surge line.
- The stress history was used to compute fatigue usage in FatiguePro.

Significant temperature differentials (i.e., the difference between pressurizer water temperature and RCS hot leg temperature) are required to produce thermal fatigue in the surge line and lower head. These temperature differentials occur during plant heatup and cooldown cycles. Other transients such as plant trips do not produce stresses above the minimum fatigue threshold. PBNP uses the “water solid” method of heatup and cooldown, which maintains relatively small temperature differentials during operation (typically less than 200°F), and results in a relatively benign effect on fatigue usage. Real plant data from various heatup / cooldown cycles since 1994 were analyzed to compute incremental fatigue usage for a heatup / cooldown cycle. The location with the highest fatigue usage in the pressurizer bottom head was determined to be the pressurizer heater tube-to-lower head (penetration) weld. For the heater penetration location, the primary stress transient is not due to insurge and outsurge, but rather the general thermal expansion stress that arises from the global heatup and cooldown of the pressurizer. This location is a stainless steel weld to the tube and clad very close to the low alloy steel pressurizer shell. A high steady state dissimilar metal thermal expansion stress is established during the heatup and is relaxed during the cooldown. It is of a magnitude that overwhelms the small stress additions coming from insurges and outsurges of fluid.

Historical data from actual plant heatup and cooldown cycles from startup to 1994 was reviewed to more accurately account for early plant operation. During the early years of operation, the differential temperatures during heatup and cooldown cycles were higher in some cases than those typically encountered in later years. A sensitivity analysis was performed by running simulated data with higher differential temperatures (by lowering the hot leg temperature) in FatiguePro to establish a correlation between maximum differential temperatures and increase in fatigue usage factor. On the average, this resulted in approximately a 50% increase in incremental fatigue usage as compared with more recent plant operation. Assuming the forecasted 100 cycles for Unit 1 (90 cycles for Unit 2) at EOLE, and assuming that the first 53 cycles for Unit 1 (39 cycles for Unit 2) of plant heatups and cooldowns occurred with the 50% increase in fatigue usage, the expected cumulative fatigue usage for the limiting (heater penetration) location is significantly less than 1.

The analysis demonstrated acceptable structural integrity for these pressurizer locations for a 60-year projected life of the plant. Projected combined fatigue usage factors (including in-surge/out-surge) for the three bounding locations were computed to be:

Table 4.3.5-1Pressurizer Lower Head Fatigue Results Including Insurge/Outsurge

Location	Material	CUF (60 yr)[i]
Pzr. Heater Penetration	SA 213 Type 316	0.057
Pzr. Inst. Penetration	SA 276 Type 316	0.0123
Pzr. Surge Nozzle (safe-end)	SA 182 Type 316	5.0E-7

i. The most limiting Unit 1 or 2 CUF is shown.

For confirmation purposes, the PBNP Fatigue Monitoring Program will continue into the period of extended operation to monitor fatigue usage at the fatigue sensitive locations.

The analyses associated with verifying the structural integrity of the pressurizers have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.6 Reactor Coolant Pump Structural Integrity

The PBNP Reactor Coolant Pumps were designed and manufactured prior to the inclusion of pumps into the scope of ASME Code. Thus, the PBNP RCPs do not have a classical ASME Class 1 fatigue analysis.

Although the PBNP reactor coolant pumps were designed and manufactured prior to the inclusion of pumps into the scope of ASME Code, the PBNP reactor coolant pumps were designed and manufactured to the intent of Section III of the 1965 Edition of the ASME Code.

The areas of the reactor coolant pump that form the reactor coolant pressure boundary would thus be subject to an ASME type stress analysis. These components are the casing, the main flange, the main flange bolts, and the thermal barrier flange.

The internal reactor coolant pump components are not reactor coolant system pressure boundary components and are not considered in the generic stress analyses performed for the Westinghouse Model 93 reactor coolant pumps.

The main flange bolts, the main flange, and the casing were analyzed to ASME Code rules, including a fatigue evaluation, in the Westinghouse Model 93 generic stress reports. The thermal barrier, the seal housing, and the seal housing bolts were included in a Westinghouse Model 93 generic stress analysis, which evaluated steady state operating conditions and the anticipated transient without trip (ATWT) event, an emergency condition, to ASME Code rules. For Point Beach, no transients were specified for the auxiliary nozzles for injection and cooling water and no analysis of these areas is contained in the generic stress reports.

The main flange bolts were analyzed for fatigue and found to have a usage factor of 0.29. The fatigue waiver methodology was not used for these bolts. This usage factor is calculated on the basis of the 200 start up/ shutdown cycles. This analysis determined that the transient conditions other than start up/ shutdown produced stresses so low as not to contribute to the fatigue usage of the main flange bolts.

A fatigue analysis was performed for the main flange. A usage factor of 0.025 was calculated on the basis of the 200 start up/shutdown cycles. The analysis determined that the transient conditions other than start up/shutdown produced stresses so low as not to contribute to the fatigue usage of the main flange. This is because the thermal barrier serves to isolate the main flange from temperature transients smaller than start up and shutdown.

The pump casing was analyzed and concluded that the fatigue usage factor for the casing is zero.

The Steam Generator Replacement and Power Uprate evaluations evaluated the adequacy of the reactor coolant pumps for uprated power conditions for a 60-year operating period. New NSSS transient data was created for the uprated power project. The revised transient set was reviewed against the original reactor coolant pump design transients. Generally, the revised transient sets were bounded by the original reactor coolant pump design transient sets. However, the revised transient sets included some transients that were not included in the original reactor coolant pump design transients. These additional transients were evaluated in the justification of the adequacy of the reactor coolant pump for uprated conditions for a 60-year operating period. The revised cycle count for a 40-year operating period was determined to also bound a 60-year operating period.

For the transients that were not bounded by the original design specification transients the ASME fatigue waiver criteria was used to the justify the adequacy of the reactor coolant pumps for the uprated power conditions for a 60-year operating period. The temperature difference for a significant temperature fluctuation per Paragraph N-415.1 (d) and the pressure difference for a significant pressure fluctuation per Paragraph N-415.1 (b) were calculated. These were then used to demonstrate that the new or revised transients associated with the Replacement Steam Generator and Power Uprate projects were not significant per the Code fatigue waiver criteria and thus do not contribute to the cumulative usage factor for the reactor coolant pump components.

The referenced evaluations confirmed that the design of the Model 93 reactor coolant pump meets the applicable ASME Code requirements for structural integrity at the revised RCS conditions associated with the uprated core power of 1678 MWt (NSSS power of 1684 MWt) for up to a 60-year life.

The analyses associated with verifying the structural integrity of the reactor coolant pumps have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.7 Pressurizer Surge Line Structural Integrity

Detailed fatigue analyses of the pressurizer surge lines were performed in response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification” (Reference 4). The analyses were performed in accordance with the requirements of Section III of the ASME Code. The methodology and results are presented in WCAP-13509, “Structural Evaluation of the Point

Beach Units 1 & 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification" (Reference 5).

The Westinghouse analysis initially developed surge line transients from a number of sources. The transients were developed following the same general approach originally established for the Westinghouse Owners Group. The transients from the Westinghouse Systems Standard Design transient set were refined through the use of PBNP specific and other similar plant surge line monitoring results, PBNP operational procedures, and historical plant operational information. The transient refinements included the potential thermal effects of thermal stratification and striping.

The transient information was used as input to a structural and stress analysis of the surge lines for the two units. The results of the analysis, following minor hanger and pipe whip restraint modifications, showed that the ASME Code stress limits and cumulative usage factor requirements were acceptable for the remainder of the original license period.

Subsequently, the PBNP specific surge line fatigue analysis was re-evaluated considering the operational conditions associated with power uprate and a 60-year operating period. The transient sets were reviewed for the new conditions. The majority of the transients defined for original power levels for 40 years were found to be bounding for uprated conditions for 60 years. Some of the feedwater transients required minor revision due to a change in feedwater temperatures associated with the proposed power uprate. The impact of the changes in the revised RCS conditions, thermal design transients, and the 60-year life were factored into determining the ASME stress levels and allowables for the surge line.

The results of the evaluation for the pressurizer surge line stratification showed that the power uprate conditions changed the fatigue usage factors at the location of the highest usage factor by a negligible amount. The calculated change in the loadings on the pressurizer nozzle due to stratification for the power uprate conditions was not considered significant. The results of the original evaluation for the surge line, WCAP-13509, remain unchanged for the 60-year operating period.

The analysis associated with verifying the structural integrity of the pressurizer surge line piping has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

For License Renewal, continuation of the Point Beach Fatigue Monitoring Program into the period of extended operation will assure that the design cycle limits are not exceeded. The Fatigue Monitoring Program is considered a confirmatory program and is described in Appendix B.

4.3.8 Pressurizer Spray Header Piping Structural Integrity

Piping connections to the RCS were evaluated in response to NRC IB 88-08 (including supplements 1 through 3) “Thermal Stresses in Piping Connected to Reactor Coolant Systems” (Reference 6). Two unisolable piping connections were identified that have the potential to be subjected to thermal stratification or temperature oscillations. These lines are the auxiliary charging connection, and auxiliary spray connection. These lines were inspected with surface and volumetric inspection techniques to identify the presence of service related degradation. No service related degradation was discovered. These lines were also subject to temperature monitoring to identify and quantify thermal stratification. No thermal stratification was noted on the auxiliary charging lines. Thermal stratification was noted on one of the auxiliary spray lines, where it ties into the spray header.

To evaluate the effect of thermal stratification on the pressurizer spray line header, including the auxiliary spray line connection, fatigue analyses were performed for each unit's applicable piping system. The analyses were based on actual piping surface temperature data obtained during a 153-day period (including one startup) of direct temperature monitoring on the Unit 2 piping. The Unit 2 data was considered applicable and bounding for both units since it experienced more stratification, and the line configuration was similar. The piping transient set was developed by expanding the measured piping thermal behavior to equate to a 40-year operating period. The analyses showed that the limiting CUFs in the subject piping were 0.66 for Unit 1 and 0.33 for Unit 2.

Extrapolating the results of the original 88-08 analyses to a 60-year operating period results in CUFs of 0.99 for the Unit 1 piping system, and 0.60 for Unit 2 piping system.

In view of the lack of margin with the Unit 1 piping system analysis result for EOLE, additional analysis investigations were pursued. The original 88-08 analyses incorporated simplified analysis techniques and assumptions. It was not clear that the analysis was in fact conservative. The 88-08 fatigue analyses were re-performed using the original temperature monitoring data, and refined analysis techniques and assumptions. The re-analysis resulted in a 60-year cumulative usage factor of 0.277 for the limiting Unit 1 piping system location.

The analysis associated with verifying the structural integrity of the pressurizer auxiliary spray line, and spray header, have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.9 USAS B31.1 Piping Structural Integrity

In general, piping and associated pressure boundary components at PBNP were originally designed to the requirements of USAS B31.1, USA Standard Code for Pressure Piping. The B31.1 Code requirements assume a stress range reduction factor to provide conservatism in the piping design to account for the effects of thermal fatigue due to thermal cycling during operation. This reduction factor is 1.0 provided that the number of anticipated cycles is limited to 7000 equivalent full temperature cycles. This represents a condition where a piping system would have to be thermally cycled approximately once every 3 days over the extended plant life of 60 years. Considering this limit, a review of the piping and associated pressure boundary components included within the scope of License Renewal was performed to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Under current plant operating practices, piping and associated pressure boundary components are generally only occasionally subjected to cyclic operation. Typically, piping and associated pressure boundary components are subjected to continuous steady-state operation and operating temperatures, and only vary during plant heatup and cooldown, during plant transients, or during periodic testing. It is therefore very unlikely, for any piping system subject to thermal fatigue, that the actual number of thermal cycles would approach the assumed B31.1 limit of 7000 cycles during the period of extended operation except for the Primary Sampling System lines. Establishing sample flow from the RCS results in thermal transients and cyclic stresses whenever the RCS is above ambient temperatures. The hot leg sample line receives the highest number of thermal cycles of all piping. An evaluation of the number of thermal cycles that the hot leg sample line would be expected to experience over a 60-year period of operation was performed. The evaluation demonstrates that the PBNP hot leg sample line will not exceed 7000 thermal cycles over a 60-year operating period. Thus, no piping and associated pressure boundary components are expected to exceed 7000 thermal cycles over a 60-year operating period, and thus remain within the bounds of their original design code.

The analyses associated with USAS B31.1 piping fatigue have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(C)(1)(i).

4.3.10 Environmental Effects on Fatigue

Generic Safety Issue (GSI) 190 (Reference 7), was identified by the NRC staff because of concerns about the potential effects of reactor water environments on Reactor Coolant System component fatigue life during the period of extended operation. GSI-190 was closed in December 1999 (Reference 8), and concluded that environmental effects have a negligible impact on core damage frequency, and as such, no generic regulatory action is required. However, as part of the closure of GSI-190, the NRC concluded that licensees who apply for license renewal should address the effects of coolant environment on component fatigue life as part of their aging management programs.

Fatigue calculations that include consideration of environmental effects to establish cumulative usage factors could be treated as time-limited aging analyses (TLAAs) under 10 CFR 54 or they could be utilized to establish the need for an aging management program. In other words, the determination of whether a particular component location is to be included in a program for managing the effects of fatigue, and the characteristics of that program, should incorporate reactor water environmental effects.

To qualify as a TLAA, the analysis of concern must satisfy all six criteria defined in 10 CFR 54.3. Failure to satisfy any one of these criteria eliminates the analysis from further consideration as a TLAA. Fatigue design for PBNP Units 1 and 2 has been determined to be a TLAA, even though the design limits are based on cycles rather than an explicit time period. However, reactor water environmental effects, as described in GSI-190, are not included in the PBNP current licensing basis (CLB), such that the criterion specified in 10 CFR 54.3(a)(6) is not satisfied. Nevertheless, environmental effects on Class 1 component fatigue have been evaluated separately for PBNP to determine if any additional actions are required for the period of extended operation.

The PBNP approach to address reactor water environmental effects accomplishes two objectives. First, the TLAA on fatigue design has been resolved by confirming that the original transient design limits remain valid for the 60-year operating period, or have been projected to the end of the extended operating period. Confirmation by the Fatigue Monitoring Program will ensure these transient design limits are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment. These two aspects of fatigue design are kept separate, since fatigue design for PBNP is part of the plant CLB and a TLAA, while the consideration of reactor water environmental effects on fatigue life, as described in GSI-190, is not considered part of the PBNP CLB, nor considered a PBNP TLAA.

It is important to note that there are three areas of margin included in the PBNP Fatigue Monitoring Program that are worthy of consideration. These areas include margins resulting from actual cycle experience, severity of transients, and moderate environmental effects.

- Margin Due to Actual Cycles: It has been concluded that the original 40-year design transient set for Class 1 components is valid for the 60-year extended operating period, with the exception of hydrotest pressure tests. The design transient set has been revised to include additional hydrotest transients to ensure that enough pressure test cycles are available for a 60-year operating period, plus 25 percent. Conservative projections conclude that the design transient limits will not be exceeded. Additional margin is available in the current Class 1 component fatigue analyses since fatigue usage factors for all Class 1 components remain below the allowable value of 1.0.

- Margin Due to Transient Severity: Much of the conservatism in the fatigue calculational methodology is due to design basis transient definitions. It has been concluded that the severity of the original PBNP design transients bounds actual plant operation. Additional industry fatigue studies (Reference 9, Reference 10, Reference 11, and Reference 12) conclude that the fatigue impact of conservative design basis transient definitions by themselves bound the contributing impact of reactor water environmental effects.
- Margin Due to Moderate Environmental Effects: A portion of the safety factors applied to the ASME Code Section III fatigue design curves accounts for moderate environmental effects. While there is debate over exactly how much margin this represents, it is noteworthy to recognize this safety factor in this qualitative discussion of margin.

Considering the three margins above, the PBNP Fatigue Monitoring Program is conservative from an overall perspective. Nevertheless, specific assessment of potential environmental effects on fatigue is addressed below.

As a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term, Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260 (Reference 13), fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system vendors. The pressurized water reactor calculations, especially the early-vintage Westinghouse calculations, are directly relevant to PBNP. In addition, the transient cycles considered in the evaluation match or bound the PBNP design.

The fatigue-sensitive component locations chosen in NUREG/CR-6260 for the early-vintage Westinghouse plant were:

1) The reactor vessel shell and lower head

2) The reactor vessel inlet and outlet nozzles

3) The pressurizer surge line (including the pressurizer and hot leg nozzles)

4) The Reactor Coolant System piping charging system nozzle

5) The Reactor Coolant System piping safety injection nozzle

6) The Residual Heat Removal System Class 1 piping

Note that for the latter three component locations, INEL performed representative design basis fatigue calculations, because early-vintage Westinghouse plants, including PBNP, utilized ANSI B31.1 design methodology for the majority of the Class 1 piping.

NUREG/CR-6260 calculated fatigue usage factors for these locations utilizing the interim fatigue curves provided in NUREG/CR-5999 (Reference 14). However, the data included in more recent industry studies need to be considered in the evaluations of environmental effects.

Environmental fatigue calculations have been performed for PBNP for those component locations included in NUREG/CR-6260 using the F_{en} methodology contained in NUREG/CR-6583 (Reference 15) for carbon/low alloy steel material, and NUREG/CR-5704 (Reference 16) for stainless steel material.

The results are summarized below:

Reactor Vessel Locations

Westinghouse evaluated the effect of environmental factors on the fatigue life for the PBNP RPV core support pads, inlet nozzles, and the outlet nozzles. The approach contained in NUREG/CR-6583 was used.

In order to consider the environmental impact on the cumulative fatigue usage factors, the approach contained in NUREG/CR-6583 was used. NUREG/CR-6583 states that the fatigue life of carbon steel and low-alloy steel will decrease significantly “when five conditions are satisfied simultaneously, viz., applied strain range, service temperature, DO (dissolved oxygen) in the water, sulfur content of the steel are above a minimum threshold level, and the loading strain rate is below a threshold value.” In other words, all values must exceed their threshold values for environmental effects to have an impact.

Furthermore, NUREG/CR-6583 discusses the impact of environmental effects during tensile-stress-producing transients versus compressive-stress-producing transients. According to that discussion, the reactor water environment during tensile-stress-producing transients (rather than during compressive-stress-producing transients) affects fatigue life for carbon and low-alloy steel. This is true because when a surface is in tension, any cracks in the surface are exposed and opened to the environment (see Section 4.2.2 of NUREG/CR-6583 for more details).

The minimum threshold value for the dissolved oxygen (DO) content of the reactor coolant is 0.050 ppm (Section 4.2.4 of NUREG/CR-6583). The maximum DO content during full power plant operation is less than 0.005 ppm (because dissolved oxygen is scavenged from the reactor coolant system by adding hydrogen). This value is 10 times less than the threshold value. The dissolved oxygen content may be higher during the heat-up transient; however, while the reactor coolant system is heating up, the inner surfaces will be in compression, and environmental effects will be small. As such, environmental effects are negligible because all five conditions do not exceed their respective threshold values.

Consequently the cumulative fatigue usage factors remain unchanged. All factors are less than one and are acceptable. These cumulative fatigue usage factors are summarized below.

Component	Location	Usage Factor
Outlet Nozzle	Support Pad Location	0.12181
Outlet Nozzle	Nozzle-to-Shell Juncture Location	0.02819
Inlet Nozzle	Support Pad Location	0.02990
Inlet Nozzle	Nozzle-to-Shell Juncture Location	0.02070
Core Support Pad	Attachment to Vessel Shell Location	0.73136

Additionally, the effect of environmental factors on the fatigue life for the PBNP RPV core support pads, inlet nozzles, and the outlet nozzles were evaluated. A bounding (worse case) F_{en} multiplier for the applicable material at the specific location was applied to the code based cumulative fatigue usage factor. This simplified approach resulted in acceptable results for the nozzle locations, and an environmental fatigue usage factor of 1.85 at the core support pad location. The core support pad location was reevaluated using a reduced number of “Plant Loading/ Unloading” events. Since PBNP is not operated as a load follow plant, the number of “Plant Loading/Unloading” events was reduced from 18300 to the forecasted 60-year number of 2600. This resulted in a calculated fatigue usage factor of 0.20, and an environmental fatigue usage factor of 0.53 at the core support pad location. It should be noted that significant additional conservatisms exist in the fatigue evaluation for the core support pad location. The fatigue analyses are based on a full transient set at uprated conditions. The fatigue analysis for CLB power conditions results in a CUF of 0.00. Thus, to date, there has been no cumulative fatigue usage for this location.

The effect of environmental factors on the fatigue life for the PBNP RPV core support pads, inlet nozzles, and the outlet nozzles has been evaluated and shown to be acceptable for the period of extended operation.

Surge Line Locations

The PBNP pressurizer surge lines were designed and constructed to the USAS B31.1-1967 Power Piping Code. Originally, no specific fatigue analysis was performed for this piping. However, subsequently, detailed structural and fatigue analyses were performed in response to NRC IB 88-11, “Pressurizer Surge Line Thermal Stratification.” These evaluations were performed to the requirements of ASME Section III, and were based on a design transient set, which also included the effects of thermal stratification. The summary results of these specific analyses are presented in Westinghouse WCAP-13509, “Structural Evaluation of the Point Beach Units 1 & 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification.”

Specific fatigue usage factor information for the PBNP pressurizer surge lines was obtained from WCAP-13509. The fatigue usage factors calculated in the noted WCAP are based on a full design transient set, including stratification, for a 40-year operating period.

The highest CUF is 0.99, and is located at a welded attachment for a whip restraint on the middle section of the Unit 1 surge line. However, the welded attachment is on the outside surface of the pipe where environmental conditions do not apply (not exposed to reactor coolant), and the effects of the welded attachment do not apply to the inside surface where environmental conditions are applicable. Thus, even though this is the location of the maximum CUF, environmental fatigue is not applicable. It should be noted that the fatigue usage at this location was accumulated during the period when the piping support configuration allowed binding of the pipe within the restraint system. The restraint was modified to prevent future binding, and thus, no further fatigue accumulation occurs at this location.

The next highest CUF for Unit 1, and the highest CUF for Unit 2, occurs at the reducer below the pressurizer surge nozzle. The CUF is 0.7. An environmental fatigue multiplier of 15.35 for austenitic stainless steel was applied to the code fatigue calculation result. The resulting environmental fatigue usage factor for the limiting location in the pressurizer surge line was calculated and found to be 10.75.

Since the initial surge line EAF calculations, resulting from fatigue calculations based on design transients including stratification, did not produce acceptable results, EAF for the surge line was then evaluated using actual monitored, and forecasted fatigue data.

The EPRI FatiguePro software program was customized to monitor fatigue-critical locations in the surge lines and pressurizer's lower head at PBNP. An analysis was performed based on available template sets of real plant data to determine the incremental fatigue usage factor for known plant transients, including the effects of “insurge/outsurge” and environmentally-assisted fatigue (EAF). Cumulative usage factors for the operating life of the plant were computed based on the results of real plant data, and expected future usage was computed using projections of expected plant cycles.

The technical approach is summarized as follows:

- The flow rate in the surge line was computed based on a mass balance approach, using the incoming spray demand and the rate of change of the pressurizer water level, taking into account temperature effects.
- A 2-dimensional model was created to take into account (a) the advance and time delay of colder water from the hot leg into the surge line and lower head of the pressurizer, and (b) the heat transfer between the fluid and metal.
- This approach has been verified to be conservative based on available thermocouple data from another plant, as well as plant-specifically for PBNP by comparing the surge line temperature instrument reading with the FatiguePro calculated water temperature in the region of the surge nozzle. The temperatures at the nozzle and lower head are calculated in FatiguePro completely independently from the surge line temperature instrument.
- Finite element models (including thermal sleeves in the pressurizer surge nozzle and hot leg RCS surge nozzle) were created to compute “Green's Function” stress responses to step changes in temperature at various zones in the pressurizer. Stresses could then be computed based on the calculated fluid temperatures at the various zones in the pressurizer and surge line.
- The stress history was used to compute fatigue usage in FatiguePro.

Significant temperature differentials (i.e., the difference between pressurizer water temperature and RCS hot leg temperature) are required to produce thermal fatigue in the surge line and lower head. These temperature differentials occur during plant heatup and cooldown cycles. Other transients such as plant trips do not produce stresses above the minimum fatigue threshold. PBNP uses the “water solid” method of heatup and cooldown, which maintains relatively small Temperature differentials during operation (typically less than 200°F), which results in a relatively benign effect on fatigue usage. Real plant data from various heatup/cooldown cycles since 1994 were analyzed to compute incremental fatigue usage for a heatup/cooldown cycle. The location with the highest fatigue usage in the pressurizer bottom head and surge line was determined to be the pressurizer heater tube-to-lower head (penetration) weld.

A detailed discussion of the Pressurizer fatigue results may be found in the Pressurizer environmental fatigue evaluation discussion.

Historical data from actual plant heatup and cooldown cycles from startup to 2001 was reviewed to more accurately account for early plant operation. During the early years of operation, the differential temperatures during heatup and cooldown cycles were higher in some cases than those typically encountered in later years. A sensitivity analysis was performed by running simulated data with higher differential temperatures (by lowering the hot leg temperature) in FatiguePro to establish a correlation between maximum differential temperatures and increase in fatigue usage factor. On the average, this resulted in approximately a 50% increase in incremental fatigue usage as compared with more recent plant operation. The pressurizer surge line location applicable to the NUREG/CR-6260 analysis is the hot leg surge line nozzle. This location is also the PBNP fatigue limiting location in the pressurizer surge line as identified by fatigue analysis based on real plant operational data.

The plant-specific analysis of the hot leg surge line nozzle produces a projected 60-year CUF of 0.00147 (Unit 1) and 0.00079 (Unit 2), based on actual plant transients and the design number of heatup and cooldown cycles. The potentially more severe operation of the plant in the early years of operation are accounted for by applying a 1.5 multiplier on the computed fatigue usage for the first 53 cycles for Unit 1 and the first 39 cycles for Unit 2. These early cycles represent those prior to 1994, when the FatiguePro software was installed. Since this location is stainless steel, the worst-case multiplier of 15.35 produces at EAF adjusted CUF of 0.0226 (Unit 1) (0.0122 for Unit 2), which is acceptable.

The environmental effects on fatigue evaluation for the hot leg surge line nozzle was also evaluated using an alternate approach. The alternate evaluation was also based on FatiguePro monitoring. The evaluation used over 9 years of actual plant data from 1994 through 2003. This evaluation used a mean plus one standard deviation methodology to produce 60-year CUFs of 0.0383 and 0.007132 for Units 1 and 2, respectively. The most conservative value of 0.0383 was multiplied by the worst-case multiplier of 15.35 to yield an EAF adjusted CUF of 0.588, which is also acceptable.

USAS B31.1 Locations

As with the older vintage Westinghouse plants evaluated in NUREG/CR-6260, detailed ASME fatigue usage calculations did not exist for the PBNP RHR tee, charging nozzle and safety injection (accumulator) nozzle, because the design basis for the PBNP piping is USAS B31.1, which does not require specific fatigue analysis.

The design inputs for PBNP (e.g. material, geometry) were compared to those summarized in NUREG/CR-6260 for these three components. The PBNP charging nozzle and safety injection nozzle were determined to be identical in terms of materials and geometry as those presented in NUREG/CR-6260. The PBNP RHR tee is identical in terms of material, but is larger than the RHR tee analyzed in NUREG/CR-6260.

PBNP specific simplified ASME III code fatigue analyses were performed on the subject B31.1 locations to ensure that bounding fatigue information was used in the environmental effects on fatigue evaluation.

RHR Tee

The specific location of concern is the RHR tee, where the RHR line ties into the accumulator injection line. The location is identical to the location evaluated in NUREG/CR-6260.

To ensure bounding fatigue information was used, a PBNP specific simplified ASME Section III fatigue analysis has been performed. The results of the PBNP specific fatigue evaluation show that the cumulative fatigue usage at EOLE is 0.0146 for the RHR tee. A bounding environmental fatigue multiplier of 15.35 for austenitic stainless steel was applied to the code fatigue calculation result. The resulting environmental fatigue usage factor for the RHR tee was calculated and found to be 0.22. Thus, since the environmental fatigue usage factor is less than 1.0, this location is acceptable from an environmental fatigue standpoint.

Accumulator Nozzle

The specific location of concern is the safety injection (accumulator) nozzle, where the safety injection (accumulator) line ties into the RCS main loop piping.

To ensure bounding fatigue information was used, a PBNP specific simplified ASME Section III fatigue analysis has been performed. The results of the PBNP specific fatigue evaluation show that the cumulative fatigue usage at EOLE is 0.0013 for the safety injection (accumulator) nozzle. A bounding environmental fatigue multiplier of 15.35 for austenitic stainless steel was applied to the code fatigue calculation result. The resulting environmental fatigue usage factor for the safety injection (accumulator) nozzle was calculated and found to be 0.02. Thus, since the environmental fatigue usage factor is less than 1.0, this location is acceptable from an environmental fatigue standpoint.

Charging Nozzle

The specific location of concern is the CVCS normal charging nozzle, where the CVCS charging line ties into RCS main loop piping. The location is identical to the location evaluated in NUREG/CR-6260.

To ensure bounding fatigue information was used, a PBNP specific simplified fatigue analysis has been performed using actual plant transients experienced, and forecasted future transients. The results of the PBNP specific fatigue evaluation show that the fatigue usage is 0.12 for the CVCS normal charging nozzle. An effective environmental fatigue multiplier of 6.99 was calculated for the location and applied to the code fatigue calculation result. The resulting environmental fatigue usage factor for the CVCS normal charging nozzle was calculated and found to be 0.83. Thus, since the environmental fatigue usage factor is less than 1.0, this location is acceptable from an environmental fatigue standpoint.

Pressurizer

In addition to the NUREG/CR-6260 locations, the PBNP pressurizers were evaluated for the effects of coolant environment on fatigue, including insurge/outsurge transients, in accordance with Applicant Action Item 3.3.1.1-1 of the pressurizer Generic Technical Report WCAP-14574-A (Reference 17).

Environmental effects of fatigue on the Point Beach pressurizers was evaluated using the CLB design transient set. A summary of the PBNP pressurizer environmental fatigue evaluation is presented below:

The PBNP pressurizers original design analyses are contained in their respective code stress reports. The surge nozzle analysis was subsequently updated for thermal stratification pipe loads. The PBNP pressurizer stress reports were also modified to incorporate the effects of the revised parameters, design transients and loads for the Point Beach RSG/Uprating Program.

This calculation re-evaluates the cumulative fatigue usage factors for the following locations in the PBNP pressurizers considering the environmental effects on fatigue:

- Spray Nozzle
- Surge Nozzle
- Junction of the Upper Head and Shell
- Safety and Relief Nozzle
- Instrument Nozzle
- Heater Well

Appendix B of MRP-47 (Reference 3) provides methods for performing fatigue usage factor evaluations of reactor coolant system and primary pressure boundary components when the effects of reactor water on fatigue initiation life are judged to be significant. For environmental factors to have an impact on fatigue usage of carbon and low alloy steels, the applied strain range, service temperature, and dissolved oxygen in the water must exceed their threshold values, and the loading strain rate must be below its threshold value. Similar thresholds are set for stainless steels, with the exception of dissolved oxygen. If one or more of the thresholds is not met, the environmental effects on fatigue are judged to be insignificant.

The minimum threshold value for dissolved oxygen content of the reactor coolant is 0.050 ppm (Section X-2400 of MRP-47). The maximum dissolved content during full power plant operation is less than 0.005 ppm (because dissolved oxygen is scavenged from the reactor coolant system by adding hydrogen). This value is one-tenth of the threshold value. Since the dissolved oxygen content is well below the threshold value, environmental effects on the fatigue usage of the carbon and low alloy steel components in the pressurizer are negligible. Thus, the cumulative usage factors for carbon and low alloy steel components remain unchanged.

The following paragraphs describe the environmental fatigue evaluations performed for each of the critical locations identified above:

Spray Nozzle

For the spray nozzle, explicit environmental fatigue correction factors (F_{en}) were calculated on a load-pair basis using the methodology described in Appendix B of MRP-47.

The environmental fatigue correction factor for stainless steel is given by:

$F_{en} = \exp[0.935 - T^*O^*\varepsilon'^*]$

The transformed T*, O*, ε'* and resulting F_{en} were calculated for each load pair where thresholds were exceeded, and the partial fatigue usage for that load pair was multiplied by F_{en} to obtain the usage for that load pair corrected for environmental effects. This process was repeated for each of the load set pairs contributing to the fatigue of the spray nozzle safe end.

The fatigue usage factor for the safe end of the spray nozzle corrected for environmental effects is 3.2814, which is not acceptable.

Surge Nozzle

The highest fatigue usage was reported in carbon steel potion of the nozzle. This usage was updated for the RSG/Uprate and was listed in the RSG report. The material is SA-216-WCC (carbon steel). Since oxygen content is low (< 0.05 ppm), the fatigue usage at this location is not affected by environmental factors.

The nozzle safe end is stainless steel, SA-182 Type 316L. Updated fatigue usage calculations were not available for this location. This location, however, is subject to environmental effects.

The nozzle safe end is adjacent to the analyzed portion of the carbon steel nozzle, and has virtually the same cross-section. The nozzle safe end stresses were obtained by modifying the carbon steel nozzle stresses to account for the difference in materials.

For the surge nozzle, explicit F_{en} factors were calculated on a load-pair basis using the methodology described in Appendix B of MRP-47.

The transformed T*, O*, ε'* and resulting F_{en} were calculated for each load pair where thresholds were exceeded, and the partial fatigue usage for that load pair was multiplied by F_{en} to obtain the usage for that load pair corrected for environmental effects. This process was repeated for each of the load set pairs contributing to the fatigue of the surge nozzle safe end.

The fatigue usage factor for the safe end of the surge nozzle corrected for environmental effects is 2.3252, which is not acceptable.

Junction of the Upper Head and Shell

The upper head is cast from SA-216 WCC carbon steel, while the upper shell is fabricated from SA-302 Grade B low alloy steel. The minimum threshold value for dissolved oxygen content of the reactor coolant is 0.050 ppm (Section X-2400 of MRP-47). The maximum dissolved content during full power plant operation is less than 0.005 ppm (because dissolved oxygen is scavenged from the reactor coolant system by adding hydrogen). This value is one-tenth of the threshold value. Since the dissolved oxygen content is well below the threshold value, environmental effects on the fatigue usage of the upper head and shell junction are negligible. The cumulative usage factor for this location remains unchanged at 0.7737.

Safety and Relief Nozzle

The body of the nozzle is part of the upper head SA-216 WCC casting, while the safe end is the only part fabricated from stainless steel. The highest fatigue usage for this component was calculated for the inside surface of a section through the knuckle of the nozzle. The fatigue usage for the safe end was not calculated. Primary plus secondary plus peak stresses were provided the safe end in the original stress report. The maximum stress intensity is less than the endurance limit of the material. Therefore the fatigue usage at the nozzle safe end is zero, and environmental factors will have no impact on the safety and relief nozzle.

The cumulative usage factor for this location remains unchanged at 0.1483.

Instrument Nozzle

The instrument nozzle is a stainless steel tube penetrating the wall of the pressurizer. The tube protrudes approximately one-half inch into the interior of the pressurizer. A 0.19 inch thick pad is built up from the clad surface. The pad is the same material as the cladding. The tube is welded to the pad, resulting in a weld bead about the tube outer circumference. The tube is rolled along its length from the weld zone to the outer surface of the shell or head wall. The tube extends beyond the outer surface approximately six inches, where it is capped.

The highest stress intensities and fatigue usage occurred at the free boundary of the nozzle opening near the wall-clad interface. This location is within the wall of the vessel and is not exposed to the primary fluid. It is conservative to assume that a location on the surface of the tube or weld bead has the same fatigue usage as the limiting location.

The limiting location stresses were modified to obtain the stresses in stainless steel that would result in the same fatigue usage as for the carbon or low alloy steel.

For the instrument nozzle, explicit F_{en} factors were calculated on a load-pair basis using the methodology described in Appendix B of MRP-47.

The transformed T*, O*, ε'* and resulting F_{en} were calculated for each load pair where thresholds were exceeded, and the partial fatigue usage for that load pair was multiplied by F_{en} to obtain the usage for that load pair corrected for environmental effects. This process was repeated for each of the load set pairs contributing to the fatigue of the instrument nozzle.

The fatigue usage factor for the instrument nozzle corrected for environmental effects is 0.6293, which is acceptable.

Heater Well

The heater well is a stainless steel tube penetrating the lower head of the pressurizer. The tube protrudes approximately three-quarter inch into the interior of the pressurizer. The tube is welded to the cladding, resulting in a weld bead about the tube outer circumference. The tube is rolled along its length from the weld zone to the outer surface of the head wall. The tube extends beyond the outer surface approximately six inches, where it is welded to the assembly supporting the heater.

The maximum fatigue usage for the heater well occurs on the outside surface at the junction with the lower head.

For the heater well, explicit F_{en} factors were calculated on a load-pair basis using the methodology described in Appendix B of MRP-47.

The transformed T*, O*, ε'* and resulting F_{en} were calculated for each load pair where thresholds were exceeded, and the partial fatigue usage for that load pair was multiplied by F_{en} to obtain the usage for that load pair corrected for environmental effects. This process was repeated for each of the load set pairs contributing to the fatigue of the heater well.

The fatigue usage factor for the heater well corrected for environmental effects is 0.2739, which is acceptable.

Summary

The following table lists the results of the environmental fatigue evaluation. The fatigue usages for the spray and surge nozzle safe ends exceed 1.0 when environmental effects are considered. All other locations have fatigue usages less than 1.0 and are acceptable.

Table 4.3.10-1Summary Table of Fatigue Usage Factors with Environmental Effects

Location	Fatigue Usage Factor	
	Design	Environmental
Spray Nozzle	0.9146	3.2814
Surge Nozzle	0.6176	2.3252
Safety Nozzle	0.1483	0.1483
Junction of the Upper Head and Shell	0.7737	0.7737
Instrument Nozzle	0.1084	0.6035
Heater Well	0.0819	0.2739

Since the evaluation for the spray and surge nozzles, based on the design transient set, did not result in an acceptable EAF CUF for the Surge and Spray nozzles, the transients and transient pairs were reviewed for specific contribution to the overall component EAF CUF. The specific transient contributions to the EAF CUF are presented below:

Spray Nozzle

The load conditions contributing to most of the spray nozzle fatigue (3.09 out of 3.28) are:

Transient ID	Transient Description	Spray ΔT	Number Cycles
1a	Heatup/Cooldown	320	400
1b	Heatup/Cooldown	281	400
2Ba	Cooldown	405	200
2Bb	Cooldown	320	1000
3	Umbrella*	160	28120
4	Boron Conc. Equalization	145	23360
6	Inadvertent Auxiliary Spray	560	10

*The umbrella transient includes the following transients:

Transient Description	Number Cycles
Unit Loading at 5%/min.	11680
Unit Unloading at 5%/min.	11680
Large Step Load Decrease	200
Small Step Load Increase	2000
Small Step Load Decrease	2000
Loss of Load	80
Loss of Flow	80
Reactor Trip	400

The contributions to the fatigue usage from the above transients are:

Transient Combination	Fatigue Usage
6 - 6	0.7009
1a - 2Ba	0.9049
1a - 1a	0.3930
1b - 1a+2Ba	0.2331
2Ba - 1b	0.0757
3 - 3	0.5558
2Bb - 3	0.0230
4 - 4	0.1992

Surge Nozzle

The load conditions contributing to most of the surge nozzle fatigue (2.02 out of 2.33) are:

Transient ID	Transient Description	Number Cycles
3	Heatup to 2250 psi	2250
4	Unit Loading	29000
5	Step Load Increase and Decrease	3000

Transient ID	Transient Description	Number Cycles
15	Cooldown from 2250 psi	2250

The contributions to the fatigue usage from the above transients are:

Transient Combination	Fatigue Usage
5 - 15	0.1993
5 - 5	0.0923
3 - 5	0.1354
15 - 4	0.1287
4 - 4	1.4651

A review of the specific transient contribution to the EAF CUF results for the spray and surge nozzles demonstrates that the results of the evaluation are extremely conservative in both the severity and numbers of transients. Significant reductions in the estimates are possible if adjustments are made to remove the operational transients that are not experienced / practiced at PBNP. These would include operations with significant spray nozzle delta-Ts, and transients associated with performing load follow operations.

The EPRI FatiguePro software program was customized to monitor fatigue-critical locations in the pressurizer's spray nozzle, and lower head components at PBNP. An analysis was performed based on available template sets of real plant data to determine the incremental fatigue usage factor for known plant transients, including the effects of “insurge/outsurge” and environmentally-assisted fatigue (EAF). Cumulative usage factors for the operating life of the plant were computed based on the results of real plant data, and expected future usage was computed using projections of expected plant cycles.

The PBNP pressurizer's lower head component's environmental fatigue evaluation, including in-surge / out-surge, was performed using the EPRI FatiguePro software program to demonstrate adequate structural integrity for a projected 60-year operational period. The calculational approach used in determining the pressurizer's lower head components cumulative usage factor is the same as the approach presented in the Surge Line section discussion. Environmental fatigue usage factors were conservatively determined by applying the maximum environmental fatigue correction factor, or 15.35 for the affected component locations.

The PBNP pressurizer spray nozzle was addressed in an identical fashion. The calculational approach used in determining the spray nozzle cumulative usage factor is the same as the approach presented in the Surge Line section. The environmental fatigue usage factor was conservatively determined by applying the maximum environmental fatigue correction factor, or 15.35 for the spray nozzle location.

The following table summarizes the environmental fatigue evaluation for the PBNP pressurizer's:

Table 4.3.10-2 FatiguePro Pressurizer Environmental Fatigue Results

Location	Material	CUF[i] (60 yr)	Environmental Factor	CUF (60 yr-env)
Pzr. Heater Penetration	SA 213 Type 316	0.057	15.35	0.88
Pzr. Inst. Penetration	SA 276 Type 316	0.012	15.35	0.19
Pzr. Surge Nozzle (safe-end)	SA 182 Type 316	5E-7	15.35	7.7E-06
Pzr. Spray Nozzle (safe-end)	SA 182 Type 316	0.0137	15.35	0.21

i. The most limiting Unit 1 or 2 CUF is shown.

The results of the Westinghouse environmental fatigue evaluation coupled with the FatiguePro environmental fatigue evaluation show that the PBNP pressurizer sub-components have acceptable environmentally adjusted CUF values (i.e., less than the allowable value of 1.0).

Conclusion for Environmentally Assisted Fatigue

The effects of reactor coolant environment on component fatigue life during the period of extended operation have been evaluated at PBNP. The evaluation includes the seven component locations identified in NUREG/CR-6260, and the Pressurizer. Appropriate environmental fatigue factors have been applied to either the components design cumulative fatigue usage factor, or the components forecasted cumulative fatigue usage factor, based on actual operational transient monitoring by the EPRI FatiguePro software. The evaluations result in acceptable environmentally adjusted cumulative fatigue usage factors at EOLE for all of the component locations considered.

The Fatigue Monitoring Program is a confirmatory program that monitors loading cycles due to thermal and pressure transients for selected critical components. The program provides an analytical basis for confirming that the number of cycles established by the analysis of record will not be exceeded before the end of the period of extended operation.

4.3.11 Containment Liner Plate Fatigue Analysis

The interior 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 design basis accident conditions. The following fatigue loads, as described in FSAR Section 5.1, were considered in the design of the liner plate and are considered a time-limited aging analysis for the purposes of license renewal:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 40 for the plant life of 40 years.
2. Thermal cycling due to Containment interior temperature varying during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500.
3. Thermal cycling due to the design basis accident is assumed to be one cycle.
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 Boiler and Pressure Vessel Code, Section III, fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the plant life.

Each of the above items has been evaluated for the period of extended operation.

For item one, the number of thermal cycles due to annual outdoor temperature variations was increased from 40 to 60 for the extended period of operation. 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 Reactor Coolant System. The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 Reactor Coolant System 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 period of extended operation as it is enveloped by item two.

For item two, the assumed 500 thermal cycles was evaluated based on the more limiting heatup and cooldown design cycles (transients) for the major components of the Reactor Coolant System. The major components of the Reactor Coolant System were designed to withstand 200 heatup and cooldown thermal cycles. The originally projected number of maximum Reactor Coolant System design cycles is conservative enough to envelop the projected cycles for the extended period of operation. The actual number of Reactor Coolant System design transients is monitored to confirm that the system design transients are not exceeded. Transient monitoring is described in the PBNP License Renewal Aging Management Program Basis Document “Fatigue Monitoring Program.” Therefore, the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is considered valid for the period of extended operation.

For item three, 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 period of extended operation.

For item four, the design of the containment penetrations has been reviewed.

The liner plate (including penetration extension sleeves) incorporated the design guidance of ASME Boiler and Pressure Vessel Code, Section III, 1965 edition, Nuclear Vessels, Article 4, Paragraphs; N-412(m), N-414.5, N-412(n), and N-415.1, Figures N-414, and N-415(A); and Table N-413. The containment penetrations conform to the applicable sections of ASA N6.2-1965, “Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors.” In addition, penetration strains were limited per the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Article 4, 1965 edition. The containment penetration head fittings were designed, fabricated, inspected, and tested in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class B, 1968 edition and all addenda.

The main steam, feedwater, blowdown, and letdown systems are the only piping systems penetrating the containment that could contribute significant thermal loading on the liner plate. Due to the higher operating temperature, the main steam piping penetration was considered bounding and thus evaluated through the period of extended operation. ASME Code, Section III, N-415.1 states that a fatigue analysis is not required, provided the service loading of the vessel or component meets all of the six specified conditions. For the penetration sleeve and the sleeve end fitting (either a pipe cap or flued head) connecting the pressure piping to the sleeve, analyses were performed to verify that the six conditions of ASME Code, Section III, Subsection A, N 415.1, 1965, are satisfied for the period of extended operation. The projected number of actual operating cycles for these piping systems through 60 years of operation was determined to be less than the design limits.

The analyses associated with the containment liner plate and penetrations have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.3.12 Spent Fuel Pool Liner Fatigue Analysis

The surfaces of the spent fuel pool, fuel transfer canals, and refueling cavities are lined with stainless steel sheet material. The liner serves to provide a leak tight barrier for spent fuel storage and fuel transfer operations. The liner consists of stainless steel sheets welded to a system of embedments in the reinforced concrete structures.

The subject reinforced concrete structures are seismically designed. The liner is supported seismically. The liner serves no purpose other than providing for a leak tight barrier for a static head of refueling water or spent fuel pool cooling water. The liner does not serve a structural function.

Fatigue was not a design consideration for the liner. Thus, this is not a TLAA for PBNP.

4.3.13 Crane Load Cycle Limit

The following cranes are included in license renewal scope and in NUREG-0612 (Reference 18):

- Containment Polar Cranes
- Auxiliary Building Crane
- Turbine Hall Crane

The load cycle limit for PBNP cranes was identified as a time-limiting-aging analysis.

All PBNP cranes were designed and constructed to meet the requirements of Specification 61 of the Electric Overhead Crane Institute (EOCI-61). EOCI-61 did not require a specific fatigue analysis. As such, there are no specific fatigue analyses for PBNP cranes.

NUREG-0612 required that the design of heavy load overhead handling systems meet the intent of Crane Manufactures Association of America, Inc. (CMAA) Specification No. 70. Per guideline 7, NUREG-0612, Section 5.1.1(7), the design of the PBNP cranes listed above was evaluated in relation to the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, “Overhead and Gantry Cranes,” and of CMAA-70, “Specifications for Electric Overhead Traveling Cranes.” The PBNP cranes listed above substantially meet the criteria of CMAA-70 “Specifications for Electric Overhead Traveling Cranes,” as noted in the NRC NUREG-0612 safety evaluation. Cranes designed in accordance with CMAA-70 Class “A” service are designed for 20,000 to 200,000 load cycles.

The PBNP containment polar cranes and the turbine hall crane are used primarily during refueling outages. The PBNP auxiliary building crane is primarily used in support of material receipt (fuel and consumables), spent fuel cask transfers, and radwaste cask transfers. Occasionally, these cranes make lifts at or near their rated capacity. However, the majority of the crane lifts are substantially less than their rated capacity. Based on conservative usage assumptions, the above listed PBNP cranes are expected to make 50,000 partial load lifts and less than 5,000 at or near rated load lifts over a 60-year operating period. This is significantly less than the CMAA-70 design cycle limit for Class “A” service cranes.

The specifications for the noted travelling cranes at PBNP included rated overload cycle limits of roughly two 125 percent rated load lifts per year, and three 150 percent rated load lifts in the cranes lifetime. With the exception of the containment polar cranes, no lifts in excess of the rated load have been made. Each containment polar crane was used to support its respective units steam generator replacement project. These lifts incorporating the containment polar cranes were specifically analyzed engineered lifts incorporating temporary replacement trolleys, bridge strengthening, and temporary center poles to ensure that the original design capabilities of the cranes were not degraded. Thus, since the major cranes are not used to make routine over rated load lifts, and that special one-time over rated load maintenance lifts are addressed as specific engineered lifts, the original specified cycle limits for over rated load lifts will not be exceeded during the extended operating period.

Since the number of operating load cycles for the cranes will be fewer than the design cycles, the crane design will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.4 Fracture Mechanics Analysis

4.4.1 Reactor Vessel Underclad Cracking

The issue of underclad cracking in reactor vessels has existed since 1970 when it was first discovered at a European vessel fabricator.

Underclad cracking has occurred in the low alloy steel base metal heat-affected zone (HAZ) beneath the austenitic stainless steel weld overlay that is deposited to protect the ferritic material from corrosion. Two types of underclad cracking have been identified. Reheat cracking has occurred as a result of postweld heat treatment of austenitic stainless steel cladding applied using high-heat-input welding processes on ASME SA-508, Class 2 forgings. Cold cracking has occurred in ASME SA-508, Class 3 forgings after deposition of the second and third layers of cladding, when no pre-heating or post-heating was applied during the cladding procedure. The cold cracking was determined to be attributable to residual stresses near the yield strength in the weld metal/base metal interface after cladding deposition, combined with a crack-sensitive microstructure in the HAZ, and high levels of diffusible hydrogen in the austenitic stainless steel or Inconel weld metals. The hydrogen diffused into the HAZ and caused cold (hydrogen-induced) cracking as the HAZ cooled.

The Point Beach Units 1 and 2 RPVs do not have underclad reheat cracking nor underclad cold cracking because the vessel manufacturers did not use the welding processes, post-weld heat treating practices, and / or materials that contributed to the cracking conditions. Specifically, single layer cladding was applied using one-wire cladding processes with low heat input that did not exhibit underclad reheat cracking in evaluations of either test samples or actual nozzle cutouts. Multiple layer cladding had preheating and post-heating applied during the cladding processes precluding underclad cold cracking.

Although this mechanism is not applicable to the PBNP RPVs, and thus not a PBNP TLAA, generic fracture mechanics evaluation of Westinghouse plants initially demonstrated that the growth of underclad cracks during a 40-year plant life was insignificant. The evaluation was extended to 60 years, using fracture mechanics analysis based on a representative set of design transients with the occurrences extrapolated to cover 60 years of service life. The 60-year evaluation (WCAP-15338-A) (Reference 19) showed insignificant growth of the underclad cracks. The NRC reviewed and approved the evaluation (WCAP-15338-A) for application to all Westinghouse RPVs (Reference 20).

4.4.2 Reactor Coolant Pump Flywheel Analysis

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 that 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 extended period of operation was performed in WCAP-14535-A (Reference 21) for all operating Westinghouse plants and certain Babcock and Wilcox plants. It demonstrates 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 NRC reviewed and approved the evaluation (WCAP-14535-A) for application with certain conditions and limitations (Reference 22). PBNP verified the RCP flywheel material and invoked this analysis as the basis for reducing the frequency of performing RCP flywheel inspections (Reference 23).

The analysis associated with the structural integrity of the reactor coolant pump flywheel has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.4.3 Reactor Coolant Pump Casing Analysis (ASME Code Case N-481 Analysis)

The ASME Section XI Code, up to and including the 1998 edition, required a volumetric inspection of the RCP casing welds, and a visual inspection of the pressure boundary components. In lieu of performing the required Section XI internal visual and volumetric inspections of RCP CASS casings, a fracture mechanics analysis, supplemented by visual examinations, per the requirements of ASME Code, Case N-481 was performed for the original operating period of 40 years. This analysis is contained in the generic industry WCAP-13045 (Reference 24), and the PBNP specific WCAP-14705 (Reference 25). These analyses incorporated the effects of thermal embrittlement, and demonstrated compliance with Code Case N-481 requirements for the original 40-year operating license period.

The current ASME Section XI Code applicable for PBNP is the 1998 Edition of the code with all addenda through 2000. The NRC approved the use of this ASME Code edition at PBNP via SER (Reference 26). This code does not require pump casing weld volumetric, or routine internal visual examinations, however does require external surface examinations of the casing welds, and internal visual examinations when the RCP is disassembled for other reasons. The fracture mechanics analysis will not be revised and resubmitted to the NRC for the extended period of operation in support of applying Code Case N-481, and therefore in this application is not a TLAA for PBNP.

The GTR for Class 1 Piping and Associated Pressure Boundary Components, WCAP-14575-A (Reference 27 and Reference 28), identifies that a fracture mechanics analysis performed for the extended operating period is an acceptable means of managing thermal aging of CASS. Thus, the Code Case N-481 integrity analysis will qualify as a TLAA for PBNP in this application.

It should be noted that in the generic industry WCAP-13045, the ferrite content for all the PBNP Units 1 and 2 reactor coolant pump casing castings is less than 10%, and the Molybdenum content is 0.20 percent. Applying Table 1 of the NRC SER for Westinghouse WCAP-14575-A, the PBNP pump casing castings are considered not susceptible to thermal aging.

Westinghouse performed an evaluation of the Code Case N-481 integrity analysis to identify if it is acceptable for the extended operating period. Using PBNP specific RCP materials and the methodology from NUREG/CR-4513 (Reference 29), 60-year (end of life) fracture toughness values were calculated. The loads from the latest primary loop piping LBB analysis (Reference 30) at the Loop Pump Casings inlet and outlet nozzles were obtained. There were negligible differences in the PBNP pump casings tensile material property values due to the operating temperature and the tensile material property values used in WCAP-13045 for the stability analysis. Based on the above the fracture mechanics analysis shown in WCAP-13045 is therefore also applicable for the PBNP Units 1 and 2 RCP casings. Based on the evaluation it was found that the applied value of J (J_{app}) and the applied value of T (T_{app}) as shown in WCAP-13045 are less than the 60 year (end of life) allowable J and allowable T for the PBNP Units 1 and 2 RCP casings. Therefore the fracture toughness criteria were satisfied. The transients and cycles for the 60-year operating condition for the PBNP Units 1 and 2 are the same as the 40-year operating condition, therefore the generic fatigue crack growth analyses results documented in WCAP-13045 also remains valid for the 60-year operating condition. The results of the re-evaluation project show that the integrity analysis to ASME Code Case N-481 documented in WCAP-13045 and WCAP-14705 for the PBNP Units 1 and 2 RCP casings remain valid for the 60-year licensed operating period.

The Reactor Coolant Pump Integrity Analysis has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.4.4 Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis

The original structural design basis of the Class 1 piping systems for the Wisconsin Electric Power Company Point Beach Nuclear Plant Units 1 and 2, required consideration of dynamic effects resulting from non-mechanistic circumferential pipe breaks, and that protective measures for such breaks be incorporated into the plant design.

Subsequent to the original Point Beach design, a new concern regarding asymmetric blowdown loads was identified in 1975. These asymmetric blowdown loads could cause pressure imbalance loads both internal and external to the reactor coolant system. The resulting loads could result in damage to equipment both internal and external to the reactor coolant system not previously considered. The NRC designated this as Unresolved Safety Issue (USI) “A-2” (Asymmetric Blowdown Loads on the Reactor Coolant System). Westinghouse addressed this USI on a generic basis. The NRC reviewed and approved the generic Westinghouse LBB evaluation(s) in NRC Generic Letter 84-04 (Reference 31).

The NRC requested that PBNP incorporate the generic LBB analysis for the reactor coolant system main loop piping to eliminate from the design basis the consideration of dynamic effects of postulated ruptures in primary coolant loop piping. By letter (Reference 32) dated May 30, 1985, Wisconsin Electric (WE) requested an exemption from 10 CFR 50, Appendix A, GDC 4, based on the generic Westinghouse LBB analysis. In 1986, the NRC revised 10CFR50 Appendix A, General Design Criterion (GDC) 4, to allow the use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors. By letter (Reference 33) dated May 6, 1986, the NRC stated that WE's request for an exemption was not necessary due to the revision to 10 CFR 50, Appendix A, GDC 4, and acknowledged that PBNP was bounded by the generic Westinghouse LBB analysis and met the additional criteria identified in NRC Generic Letter 84-04.

A plant specific LBB analysis for the PBNP Units 1 and 2 primary coolant loop piping was performed by Westinghouse in 1996, and revised in 2002, and 2003. The results of the current PBNP LBB analysis are documented in WCAP-14439, Revision 2 (Reference 34). The report demonstrates compliance with LBB technology for the PBNP RCS piping based on plant specific analysis, using the methodology and criteria of Standard Review Plan Section 3.6.3 (Reference 35). The revised LBB analysis incorporates analysis parameters associated with power uprate conditions, and a 60-year operating period. This revision documents the plant specific reactor coolant system main loop piping geometry, loading, and material properties used in the fracture mechanics evaluation. Since the primary loop piping systems include cast stainless steel fittings, end of life (60-year) fracture toughness, considering the effects of thermal aging, was determined for each heat of material.

Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection sub-system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 60 years was shown to be acceptable for the primary loop piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The revised LBB Analysis has been submitted to the NRC for review and approval in accordance with 10 CFR 50, Appendix A, GDC 4 (Reference 71).

The Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). It is therefore concluded that dynamic effects of RCS primary loop pipe breaks need not be considered in the structural design basis of the PBNP Units 1 and 2 for the license renewal operating period.

4.4.5 Pressurizer Surge Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 pressurizer surge line piping was performed in 1998. The results of the analysis are documented in WCAP-15065. The report demonstrates compliance with LBB technology for the PBNP pressurizer surge line piping based on plant specific analysis. Westinghouse revised WCAP-15065 to include the NRC SER (Reference 36) approving the LBB analysis for the PBNP Units 1 and 2 pressurizer surge line piping in 2001. This revision is documented in WCAP-15065-P-A, Revision 1 (Reference 37). The pressurizer surge line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. The LBB analysis includes the effects of thermal stratification, as evaluated for the PBNP surge lines in WCAP-13509 (Reference 5). WCAP-15065-P-A documents the plant specific pressurizer surge line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the pressurizer surge line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection sub-system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the pressurizer surge line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The pressurizer surge line LBB analysis was further evaluated to determine the impacts of uprated power conditions, and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15065-P-A, remained unchanged.

The pressurizer surge line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). It is therefore concluded that dynamic effects of pressurizer surge line pipe breaks need not be considered in the structural design basis of the PBNP Units 1 and 2 for the license renewal operating period.

4.4.6 Class 1 Accumulator Injection Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 accumulator injection line piping was performed in 1998. The scope of the analysis for the accumulator injection lines also includes the residual heat removal (RHR) return line. The results of the analysis are documented in WCAP-15107. The report demonstrates compliance with LBB technology for the PBNP accumulator injection line piping based on plant specific analysis. Westinghouse revised WCAP-15107 to include the NRC SER (Reference 38) approving the LBB analysis for the PBNP Units 1 and 2 accumulator injection line piping in 2001. This revision is documented in WCAP-15107-P-A, Revision 1 (Reference 39). The accumulator injection line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. WCAP-15107-P-A documents the plant specific accumulator injection line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the accumulator injection line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection sub-system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the accumulator injection line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The accumulator injection line LBB analysis was further evaluated to determine the impacts of uprated power conditions, and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15107-P-A, remained unchanged.

The accumulator injection line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). It is therefore concluded that dynamic effects of accumulator injection line pipe breaks need not be considered in the structural design basis of the PBNP Units 1 and 2 for the license renewal operating period.

4.4.7 Class 1 RHR Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 residual heat removal (RHR) suction line piping was performed in 1998. The results of the analysis are documented in WCAP-15105. The report demonstrates compliance with LBB technology for the PBNP RHR line piping based on plant specific analysis. Westinghouse revised WCAP-15105 to include the NRC SER (Reference 40) approving the LBB analysis for the PBNP Units 1 and 2 RHR line piping in 2001. This revision is documented in WCAP-15105-P-A, Revision 1 (Reference 41). The RHR line LBB analysis includes the effects of thermal stratification. The RHR line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. WCAP-15105-P-A documents the plant specific RHR line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the RHR line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection sub-system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the RHR line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The accumulator injection line LBB analysis was further evaluated to determine the impacts of uprated power conditions, and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15105-P-A, remained unchanged.

The RHR line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). It is therefore concluded that dynamic effects of RHR suction line pipe breaks need not be considered in the structural design basis of the PBNP Units 1 and 2 for the license renewal operating period.

4.4.8 **Component / Piping Subsurface Indication Analysis**

Fracture mechanics analyses of Reactor Pressure Vessel (RPV) nozzle flaws were used to justify continued serviceability of the Unit 1 RPV. The fracture mechanics methodology was invoked to justify continued serviceability for approximately a 10-year period. With improvements in NDE equipment and techniques, the RPV nozzle indications were subsequently identified to be within ASME Code allowable limits, and directly acceptable. Thus, PBNP does not have any active TLAA's associated with piping / component subsurface indications.

RPV Outlet Nozzle-to-Shell Welds:

During Unit 1 Refueling 11 (March 1984), an inspection of the reactor vessel outlet nozzle-to-shell welds was performed. One indication in each of the nozzle-to-shell welds was identified to exceed the ASME Code allowable size (Reference 42). Fracture mechanics evaluations were performed to confirm the continued serviceability of the reactor vessel. The detailed fracture mechanics evaluation was initially submitted to the NRC for review and approval (Reference 43). The NRC accepted the initial evaluation and required follow-up inspection(s) (Reference 44). Following the second “follow-up” inspection (Unit 1 Refueling 17, April 1990), the fracture mechanics evaluation was revised, applying

WCAP-11477, “The Handbook of Flaw Evaluation for the Point Beach Units 1 and 2 Reactor Vessels,” and submitted to the NRC for review and acceptance (Reference 45).

Follow-up inspections of the Unit 1 RPV outlet nozzle-to-shell welds were performed during Unit 1 Refueling's 14 (1987), 17 (1990), and 20 (1993). The flaws that were initially discovered and evaluated in 1984 were again identified during each subsequent examination. The indications observed were consistent with the indications previously identified, with no significant changes noted. During Unit 1 Refueling 20 the indications were sized using focus beam ultrasonic techniques, and were found to meet ASME Code allowables (Reference 46).

RPV SI Nozzle-to-Shell Weld:

During Unit 1 Refueling 14 (March 1987), an inspection of the reactor vessel safety injection nozzle-to-shell welds was performed. One indication in the “A” safety injection nozzle-to-shell weld was identified to exceed the ASME Code allowable size. Fracture mechanics evaluations were performed to confirm the continued serviceability of the reactor vessel. The detailed evaluation was submitted to the NRC for review and approval (Reference 47). The NRC accepted the evaluation and required follow-up inspection(s) (Reference 48).

A follow-up inspection of the Unit 1 RPV “A” safety injection nozzle-to-shell weld was performed during Unit 1 Refueling 17 (April 1990). The flaw that was initially discovered and evaluated in 1987 was again identified during this subsequent examination. The indication observed was consistent with the indication previously identified, with no significant changes noted. During Unit 1 Refueling 17 the indication was sized using focus beam ultrasonic techniques, and was found to meet ASME Code allowables (Reference 49).

4.5 Loss of Preload

4.5.1 Containment Tendon Loss of Prestress Analysis

The PBNP Units 1 and 2 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.

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. Friction, seating, elastic, creep, shrinkage, and relaxation losses were considered in determining the final effective preload. The final effective preload was then used in evaluating the containment structure for adequacy in consideration of design basis loads, and loading combinations.

New upper limit curves and lower limit curves have been established for all tendons through the period of extended operation. The difference in the predicted final effective preload force between 40 and 60 years was determined to be insignificant. The revised upper and lower limit curves also considered a postulated failure of one percent of the post tensioning system tendon wires. The predicted final effective preload at the end of 60 years exceeds the minimum required preload for all containment tendons. Consequently, the post-tensioning sub-system will continue to perform its intended function throughout the period of extended operation.

The analyses associated with containment tendon loss of prestress have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

As a confirmatory program, the containment structure post-tensioning sub-system surveillances will continue to be performed in accordance with the Pre-Stressed Concrete Containment Tendon Surveillance Program to verify the integrity of the tendons.

4.6 Neutron Absorber

4.6.1 Spent Fuel Pool Storage Rack Boraflex

Boraflex panels were installed as part of the spent fuel pool re-racking modification at PBNP in 1979-1980. Boraflex panels are sandwiched between adjacent cells of the spent fuel storage racks. The Boraflex panels are used as a neutron absorber for stored fuel assemblies, thereby allowing closer center-to-center spacing of the fuel assemblies. The Boraflex panel design sandwiches the Boraflex between two sheets of stainless steel plates. Openings on the top of the poison plates allow venting of gases, but do not allow a significant flow path around the Boraflex material.

The Spent Fuel Pool criticality analysis credits the presence of Boraflex material located between the adjacent storage cells within the spent fuel racks. Although the analysis is not based on time assumptions, the criticality analysis allows for a limited reduction in the concentration of the neutron absorbing material located between the adjacent storage cells. Boraflex degradation studies have been based on the integrated dose expected during service for 40 years (Reference 50). Thus, this issue is considered a TLAA for PBNP.

Boraflex is boron carbide dispersed in an elastomeric silicone. When Boraflex is subjected to gamma radiation, shrinkage and the potential to develop tears or gaps in the material can occur. The radiation exposure alters the chemical properties of the polymer matrix by weakening the chemical bonds. As a result of being in a convective aqueous environment in the spent fuel pool (SFP), the silicon polymer matrix becomes degraded and silica filler and boron carbide are released.

As part of the spent fuel pool re-racking modification, PBNP initiated a surveillance program that irradiated Boraflex coupon surveillance samples with fresh spent fuel from every refueling over a 10-year period. The extent and sampling frequency for subsequent surveillances were to be based on the results of the first inspection. The initial inspection revealed that the ten Boraflex coupons had significant decreases in thickness, width, height and weight, and they were fragile and easily broken. The neutron attenuation of these samples was not significantly reduced.

As a result of the initial inspection results, PBNP requested NRC approval to revise the surveillance program to perform neutron attenuation measurements (blackness testing) on 10 full length Boraflex panels selected from those that have been exposed to the greatest number of freshly discharged fuel assemblies at the time of the surveillance. The 10 panels included 4 panels with accelerated exposure and 6 panels selected at random. The surveillance was performed at 5-year intervals. The request explained that the Boraflex panels adjacent to the two storage cell locations that had been receiving freshly discharged fuel assemblies during the previous 9 years have received an accelerated gamma dose of

1.5E10 rads, which is equivalent to that received by the average panel in 30 years. It is further stated that the 4 Boraflex panels surrounding these cells would remain the highest exposure panels after 40 years. The NRC approved the revised surveillance program via a SER (Reference 51). The SER included an additional requirement that new fuel assemblies or spent fuel with a burnup less than 38,400 MWD/MT were to be stored in a "checker-board" pattern if degraded Boraflex was discovered. Boraflex degradation was identified by the NRC in Generic Letter 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks" (Reference 52), as a potential age-related condition and is listed as a Generic Safety Issue in GSI 173.A, "Spent Fuel Storage Pool: Operating Facilities" (Reference 53). The degradation was due to gamma radiation-induced shrinkage and silica dissolution from the Boraflex panels.

The Boraflex Monitoring Program manages aging effects for the Boraflex material in the spent fuel racks. This program provides for blackness testing and areal density measurements of the Boraflex material in the spent fuel storage racks to confirm the in-service Boraflex performance. In addition, tracking of the spent fuel pool silica levels provides a qualitative indication of boron carbide loss. Neutron attenuation or blackness testing will be performed to determine gap formation, while areal density measurements will be used to ascertain the physical loss of boron carbide. Monitoring and analysis of criticality will also be performed to assure that the required 5% subcriticality margin is maintained. Based on the results of these inspections and analysis, appropriate measures will be taken to ensure the Boraflex will continue to perform its intended function. This program addresses the concerns described in NRC GL 96-04. The Boraflex Monitoring Program is described in Appendix B.

The Boraflex Monitoring Program for the Boraflex panels will provide reasonable assurance that the equipment will be adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

4.7 Wear

4.7.1 Bottom Mounted Instrumentation Thimble Tube Wear

As discussed in NRC Information Notice No. 87-44, Supplement 1, “Thimble Tube Thinning in Westinghouse Reactors” (Reference 54), 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. Therefore, the NRC staff requested that licensees perform the actions described in NRC Bulletin No. 88-09, “Thimble Tube Thinning in Westinghouse Reactors” (Reference 55). In response to this bulletin, PBNP established a program for inspection and assessment of thimble tube thinning, which was accepted by NRC to WE letter dated November 22, 1989 (Reference 56).

The original thimble tubes for both Units were replaced during the 1984 -1985 time frame. It was necessary to replace these tubes due to internal blockages / deposits. Subsequent to the original replacement, five Unit 1 thimble tubes were replaced due to vibration damage. No through wall in-core thimble tube leakage has ever been experienced at PBNP.

The Thimble tubes are inspected in accordance with the Thimble Tube Inspection Program. The program determines the frequency of inspection by calculating wear rates based on historical inspection data. Any tubes determined to be below acceptance criteria as projected to the next inspection period are repositioned, replaced, or plugged. The Thimble Tube Inspection program is described in Appendix B.

The thimble tubes have proven to be short-lived components that are replaceable on condition. The Thimble Tube Inspection Program is designed to adequately monitor thimble tube condition to ensure that the thimble tubes are capable of performing their intended function. Thimble tube wear is not a TLAA for PBNP.

4.7.2 Containment Accident Recirculation Heat Exchanger Tube Wear

PBNP has not experienced containment accident recirculation fan heat exchanger tube wear. In addition, there are no specific design analyses associated with vibration and / or fatigue associated with the containment accident recirculation fan heat exchangers. Thus, this issue is not a TLAA for PBNP.

4.8 Environmental Qualification

4.8.1 Environmental Qualification of Electrical Equipment

Environmental Qualification (EQ) Rule

The Nuclear Regulatory Commission (NRC) has established nuclear plant EQ requirements in 10 CFR 50, Appendix A, Criterion 4, “Environmental and Dynamic Effects Design Bases,” and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments (that is, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation) are qualified to perform their safety function in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

The Environmental Qualification Program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected. 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) also requires replacement or refurbishment of components qualified for less than 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,” Regulatory Guide 1.89, “Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants,” and Generic Letter 82-09, “Environmental Qualification of Safety-Related Electrical Equipment.”

PBNP is committed to compliance with 10 CFR 50.49, which provides reasonable assurance that a component can perform its intended functions during and after postulated accident conditions after experiencing the effects of inservice aging.

License Renewal Rule

The license renewal rule, 10 CFR 54, requires that for each structure and component subject to an Aging Management Review (AMR), the licensee shall demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. The Environmental Qualification Program 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. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered time-limited aging analyses (TLAA) for license renewal. The PBNP EQ Program ensures that these EQ components are maintained within the bounds of their qualification bases.

The EQ Program will manage the aging effects of components associated with EQ TLAA. Section 4.4.2.1.3 of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” states that the staff has evaluated the EQ program (10 CFR 50.49) and determined that it is an acceptable aging management program to address EQ according to 10 CFR 54.21(c)(1)(iii). This evaluation is documented in NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section X.E1, “Environmental Qualification of Electric Components.”

The EQ Program is an existing program, as currently established to meet PBNP commitments for 10 CFR 50.49, that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section X.E1, “Environmental Qualification of Electric Components.” In accordance with 10 CFR 54.21(c)(1)(iii), the EQ Program, which implements the requirements of 10 CFR 50.49, is viewed as an aging management program for license renewal. Reanalysis of an aging evaluation to extend the qualification of components under 10 CFR 50.49(e) is performed on a routine basis as part of the EQ Program.

EQ equipment is identified and tabulated in the Master List of Electrical Equipment to be Environmentally Qualified (EQML). This list references the Equipment Qualification Summary Sheets (EQSS), which contain pertinent information that establishes qualified life and applicable environmental parameters. EQ components were reviewed to determine which items were considered TLAAs. All EQSS in the EQ Program are considered to be TLAA for license renewal due to thermal, radiation, and/or cyclic aging, except for EQSS related to lubricants. Lubricants are periodically checked and replaced, and therefore, are not considered to be TLAA. The EQSS that are considered to be TLAA for license renewal are identified in Table 4.8-1.

Reanalysis of Aging Evaluations

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation or including new available aging data. Reanalysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of the Environmental Qualification Program. While a component life limiting condition may be due to thermal, radiation or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized).

The reanalysis of an aging evaluation is documented in accordance with the requirements of the PBNP quality assurance (QA) program, which requires the verification of assumptions and conclusions. Important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

- Analytical Methods - The EQ Program uses the same analytical models in the reanalysis of an aging evaluation as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, acceptable methods for establishing the 60 year normal radiation dose include multiplying the 40 year normal radiation dose by 1.5 (that is, 60 years/40years) or using the actual calculated value for 60 years. The result is added to the accident radiation dose to obtain the total integrated dose for the component. In many cases, the normal radiation dose is insignificant when compared to the accident dose. In such cases, the use of the accident dose is valid for both the 40 year and 60 year dose. For cyclical aging a similar approach may be used. Other models may be justified on a case-by-case basis.
- Data Collection & Reduction Methods - Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis per the EQ Program. Temperature data used in an aging evaluation should be 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 (while the motor is not running). A representative number of temperature measurements are conservatively 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 are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

- Underlying Assumptions - EQ 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 & Corrective Action - Under the Environmental Qualification Program, 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 (that is, sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

Conclusion

The EQ Program has been demonstrated to be capable of programmatically managing the qualified lives of the components falling within the scope of the program for license renewal. Based upon a review of the existing program and operating experience, the effective implementation of the EQ Program will provide reasonable assurance that (a) the aging effects will be managed, and (b) EQ components will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation. Therefore, the EQ Program will be an acceptable aging management program for license renewal under 10 CFR 54.21(c)(1)(iii) during the period of extended operation.

Generic Safety Issues

The NRC has completed the technical assessment of Generic Safety Issue (GSI) 168, “Environmental Qualification of Low-Voltage Instrumentation and Control (I&C) Cables,” and presented the results of their assessment to the Advisory Committee on Reactor Safeguards (ACRS), as documented in an NRC Internal Memorandum to Samuel J. Collins, Director-Office of Nuclear Reactor Regulation, from Ashok C. Thadani, Director-Office of Nuclear Regulatory Research, dated June 28, 2002.

The NRC concluded that typical cable qualification test programs include numerous conservative practices that collectively provide a high level of confidence that the installed plant cables will adequately perform during the accident events. These conservative practices support the use of a single prototype (or small number of test specimens) during the qualification test program. The NRC staff also concluded that licensee knowledge of the environment is essential to assure that the operating conditions in nuclear power plants do not exceed the qualification parameters assumed during the test. In this regard, licensee walkdowns to look for any visible signs of anomalies attributable to cable aging, coupled with the knowledge of operating environments, have proven to be effective and useful.

One of the principal findings of the NRC research conducted in support of the resolution of GSI-168 is that the current EQ process is adequate for the EQ of low-voltage I&C cables for the current license term of 40 years. Therefore, the overall EQ process provides reasonable assurance that, when qualified in accordance with the NRC regulations, the cables will perform their intended function during their qualified life. In 10 CFR 50.49, the effects of significant aging mechanisms are required to be addressed as part of the EQ of electrical equipment important to safety in harsh environments. Specifically, 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 the component's functional capability. Compliance with 10 CFR 50.49 ensures that the component (cable) will perform its intended function during accident conditions after exposure to the effects of service aging.

The NRC expects that licensees will “monitor environments (temperature and radiation) in operating plants, at least in certain critical areas, so they know where the hot-spots are” [i.e., adverse localized environments]. Knowledge of the operating environment and the condition of cables becomes critical during the service life. As stated earlier, walkdowns to look for any visible signs of anomalies attributable to cable aging coupled with the knowledge of operating environments have proven to be effective and useful.

Knowledge of operating environments is also a critical factor for license renewal. If the environmental service conditions are less severe than those used in the original qualification and cables are not degraded, then the licensees can use the margin between the operating environment and the qualification environment to analytically extend the life of the cables.

The NRC recommended the dissemination of these research results and other information discussed in the technical assessment of GSI-168, consistent with the generic communication process. On June 6, 2002 the NRC met with the ACRS and presented their technical assessment of GSI-168. The ACRS endorsed the staff's conclusions and recommendations, as documented in a letter to Dr. William D. Travers, NRC-Executive Director of Operations, from George E. Apostolakis, ACRS-Chairman, dated June 17, 2002.

The NRC issued Regulatory Issue Summary (RIS) 2003-09, “Environmental Qualification of Low-Voltage Instrumentation and Control Cables,” on May 2, 2003. RIS 2003-09 was issued to inform licensees of the results of the technical assessment of GSI-168, and requires no action or written response on the part of an addressee. This RIS states that the technical assessment of GSI-168 is complete and the research findings are published in NUREG/CR-6704, “Assessment of Environmental Qualification Practices and Condition Monitoring Techniques for Low-Voltage Electric Cables.”

Aging evaluations are ongoing throughout the plant life at PBNP. One of the underlying assumptions of the EQ Program is that EQ 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 (e.g., cable), the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification basis and conclusions.

The Cable Condition Monitoring Program is a new program that has been established specifically for license renewal. This program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation or moisture. The program requires visual inspection of a representative sample of accessible electrical cables and connections in adverse localized environments once every 10 years for evidence of jacket surface degradation. The scope of this program includes accessible non-EQ electrical cables and connectors, including control and instrumentation circuit cables. Although the scope of this program is aimed at non-EQ electrical cables and connectors it is equally applicable to EQ electrical cables, since no distinction is made as to whether the cables being inspected are EQ or non-EQ.

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
1.1.A	Westinghouse	Fan Motor	ABDP/Frame 504-US/ Class F	Yes
1.1.B	Westinghouse	Splice (Motor Lead to Field Cable)	Westinghouse Dwg. #206C391	Yes

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
1.1.G	Westinghouse	Splice (Field Cable to EPA - Inside containment)	Westinghouse Dwg. #206C391	Yes
11.2.A	EXO-Sensor	Hydrogen Analyzers	110D006	Yes
11.2.A.1	EXO-Sensor	Hydrogen Analyzer Platform Components (Whitey Cylinder, Nupro Shut Off Valve, KIP Solenoid Valve)	108D016	Yes
11.2.B	Bell & Howell, CEC Div.	Pressure Transducer	CEC 1000-0208	Yes
11.2.C	TAYCO Engineering	Resistance Temperature Detectors	180-3317	Yes
14.1.D	Rome	Control Cable (except 1RC-00515)	600 V PVC-Insulated, PVC-Jacketed	Yes
14.10.A	Control Products	In-core Thermocouples	Chromel/Alumel (ISA Type K #20 Ungrounded Junction SST Sheathed MI Insulated)	Yes
14.10.B	Veam	T/C Connectors	CIR06WP-16-10S-TC; CIR030WP-16-10P-TC; CIR01WE-8-2P-TC-.125; CIR06WE-8-2S-TC-.375	Yes
14.11.A	Conax	Resistance Temperature Detectors	7760-10000-01	Yes
14.12.A	Crosby	Lift Indicating Switch Assemblies	D00191	Yes
14.12.B	Veam, American Boa	Connector & Flexible Conduit	CIR06NW1-20-15S-18 CIR01NW1-20-15P	Yes
14.3.A.1	Target Rock	Solenoid Valve, High Pressure	80B-001	Yes
14.3.A.2	Target Rock	Solenoid Valve, High Pressure	80B-001	Yes

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
14.4.G	Nutherm	Electrical Panel (PB1 PT-00420C & PB1 LT-00426)	Nutherm Dwg. No. 5001-56862-43, REV 1	Yes
14.4.K	Electroswitch	Transfer Switch (PB1 PT-00420C & PB1 LT-00426)	20KD-914A8-1	Yes
16.1.A	ASCO	Solenoid Valve	206-381-2F	Yes
17.1.A	Westinghouse	Pump Motor (SI)	688.5-H Frame, Class B THERMALASTIC EPOXY INS.	Yes
17.1.B	Raychem	Splice (Motor Lead to Field Cable)	NMCK8 & NHVT-I	Yes
17.1.C.1	Okonite	Power Cable	Okonex (Butyl)-Insulated, Okoprene (Neoprene)-Jacketed 5K VAC, (Cable Code A04)	Yes
17.1.C.2	Okonite	Power Cable	1-C 250KCMIL(37X) BC-SS-.115 Okoguard-.024 SC EPR-.005 CC Tape-DW Tape-Tape-.080 Okolon w/Seq Print 5K VAC	Yes
17.10.A	Westinghouse	Pump Motor	TBDP/Frame 444TS Class B Premium Moisture Resistant (PMR) Insulation	Yes
17.18.A	Honeywell Microswitch	Limit Switches	1LS10, 11LS10, 11LS1	Yes
18.1.A	Gamma-Metrics	Neutron Detector Assembly (Fission Chamber and Mineral Insulated Detector Cable)	P/N 200574-115	Yes

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
18.1.C	Gamma-Metrics	In-Containment Cable Assembly (Except Junction Box); Amplifier Cable Assembly	200712-085/090 (Unit 1/2); 200722-210/200 (Unit 1/2)	Yes
18.1.D	Parker Hannifan Corp.	Junction Box O-Ring Seal	2-442-S604-70	Yes
18.1.E	Conax	Electrical Penetration Assembly and Penetration Splices	7V47-10001-01	Yes
21.1.E	Rome	Control Cable, 600 V	600 V PVC-Insulated, PVC-Jacketed, Control Cable	Yes
21.2.E	Rome	Control Cable, 600 V	600 V PVC-Insulated, PVC-Jacketed, Control Cable	Yes
22.4.A	Okonite	Control Cable, 600 V	1/C 600 V 500KCMIL EPR insulated, Okolon Jacketed Power Cable, Cable Code B23X	Yes
22.5.A	Nutherm	Fuse and Fuse Blocks	Gould Shawmut A4BQ-800 fuse; Gould Shawmut ATM-3 fuse; Marathon 6M30A2SQ fuse block	Yes
22.6.A	Nutherm	GE/Nutherm Molded Case Switches/Circuit Breakers	Circuit Breakers	Yes
3.2.A	General Atomics	Radiation Monitor	RD-23	Yes
3.2.D	Raychem	Splice (Field Cable to EPA and Monitor to Field Cable)	WCSF-N (Amphenol Coax. Connectors)	Yes
5.1.A	Westinghouse	Pump Motor (RHR)	TBDP/Frame 445TS Class B Thermalastic Epoxy Ins.	Yes
6.1.A	Westinghouse	Pump Motor (CCW)	ABDP, Frame 504-US, Ins Cls B, S/N 2S-68, 3S-68	Yes

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
6.1.B	Westinghouse	Pump Motor (CCW)	ABDP, Frame 504-US	Yes
6.1.B.1	Westinghouse	Pump Motor (CCW)	NBDP, Frame 449TS, Ins Cls H	Yes
7.2.E	Okonite	Instrumentation Cable (Fan Rooms)	Okotherm (Silicone Rubber) - Insulated & Okoseal (PVC) - Jacketed Twisted Shielded Pair	Yes
9.1.B	ASCO	Solenoid Valve	NP 8314 C28E	Yes
9.2.A	ASCO	Solenoid Valve	NP 8314 C28E	Yes
PS.6.1	United Controls/ Reliance	Pump Motor (Appendix R spare)	TEFC, Frame 449TS, Ins Cls H, UCI 3570-1-1	Yes
PS.G.1	Okonite	Tape Splices	T-95 (EPR), #35 (Neoprene), and Splicing Cement	Yes
PS.G.12	Rockbestos	Coaxial Cable (instrumentation)	RSS-6-104/LE, RSS-6-105/LE, RSS-6-113/LE	Yes
PS.G.15	Limitorque	Torque/Limit Switch for MOVs	Fibrite	Yes
PS.G.19	Raychem	Cable Splice	WCSF-N	Yes
PS.G.21	Raychem	Cable Splice	NPKV, NPK (X, C, S, P)	Yes
PS.G.22	Rockbestos	Cable (Control, Power and Instrumentation)	Firewall III Chemically Cross-Linked Polyethylene Wire	Yes
PS.G.23	Rockbestos	Cable (Control, Power and Instrumentation)	Firewall III Irradiation Cross-Linked Polyethylene Wire; Firewall III SIS Wire	Yes
PS.G.24	Raychem	Cable Splice	NMCK	Yes
PS.G.25	EGS	Splice and Connector	Grayboot Connector GB-1A, GB-2A, GB-3A	Yes
PS.G.26	Bechtel/ Raychem	Splice (Field Cable to EPA)	Bechtel Dwg. #SK-E-165/SFR	Yes

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
PS.G.27	Raychem	Cable Splice	WCSF-N	Yes
PS.G.28	3M	Tape Splices	Scotch 130C and 33+	Yes
PS.G.29	3M	Tape Splices	Scotch 130C, 70 and 17	Yes
PS.G.30	Namco	Limit Switches	EA 180-11302, 12302, 14302, and 15302	Yes
PS.G.31	Fisher	Electro-Pneumatic Transducer	546 & 546NS	Yes
PS.G.32	Westinghouse	Electrical Penetration Assembly	Westinghouse Modular Penetration	Yes
PS.G.33	Crouse Hinds/ Westinghouse	Electrical Penetration Assembly	Welded Canister Type	Yes
PS.G.34	Foxboro	Transmitter (Pressure/ Differential Pressure)	N-E10 Series (N-E11, N-E13)	Yes
PS.G.35	Limitorque/ Reliance	Valve Motor Operator	SMB Series/Class RH Insulation	Yes
PS.G.36	Limitorque/ Reliance or Porter Peerless	Valve Motor Operator	SMB Series/Class B Insulation	Yes
PS.G.37	Limitorque/ Reliance or Porter Peerless	Valve Motor Operator	SMB Series/Class B Insulation (with Dings 6200 Motor Brake in PB1 SI-00871A, B and PB2 SI-00871A, B)	Yes
PS.G.38	ASCO	Transfer Switch (Manual)	Catalog #486E4C	Yes
PS.G.39	Brand-Rex	Instrumentation Cable	Ultrol 2/C #16 Twisted Shielded Pair (XLPE Insulation and Hypalon Jacket)	Yes
PS.G.4	EGS	Splice and Connector	Grayboot Connector GB-1, GB-2, GB-3	Yes
PS.G.40	Boston Insulated Wire Co.	Instrumentation Cable	Bostrad7 Twisted Shielded Pair	Yes

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
PS.G.41	Rosemount	Conduit Seal	353C, 353C1	Yes
PS.G.42	Rosemount	Transmitter (Differential Pressure)	1154DP6RAN0034 1154HP5RGN0080 with 1159A50A Sensors and 353C1 Conduit Seals	Yes
PS.G.43	Kerite	Control Cable	600V FR-Insulated, FR-Jacketed Control Cable	Yes
PS.G.44	Kerite	Power Cable	600 V HTK-Insulated, FR-Jacketed Power Cable	Yes
PS.G.45	Okonite	Cable (Control and Power)	3/C 600V FMR (Ethylene Propylene) insulated, Okolon Jacketed Cable	Yes
PS.G.46	Okonite	Instrumentation Cable	Okotherm (Silicon Rubber) Insulated; Okoseal (PVC) Jacketed Twisted Shielded Pair	Yes
PS.G.47	Conax	Electrical Conductor Seal Assembly	N-11027-01	Yes
PS.G.48	Conax	Resistance Temperature Detectors	7102-10000-01/02/03/04	Yes
PS.G.49	Anaconda	Cable (Control, Instrumentation, Switchboard & T/C)	FR-EP Insulated Cables	Yes
PS.G.50	Conax	Electrical Conductor Seal Assembly	N-11001-64, N-11006-53, N-11006-64, 7202-11000-01	Yes
PS.G.51	Scotch	Splice (Motor Lead to Field Cable)	Scotch 70 Silicone Rubber Tape Insulation	Yes
PS.G.52	Conax	Thermocouples	7366-10000-01 & 02	Yes
PS.G.53	Target Rock	Solenoid Valve	80B-001BB-3 (Valve Assembly 1031210-3)	Yes
PS.G.54	ASCO	Solenoid Valve	206 Series	Yes
PS.G.55	Marathon	Terminal Block	1500 Series	Yes

Table 4.8-1EQ TLAA SUMMARY

EQSS	Vendor	ITEM DESCRIPTION	Model	TLAA Summary
PS.G.56	ASCO	Solenoid Valve (Normally De-energized & Intermittently Energized During Accident)	NP8314, NP8316, NP8320 Series (EPDM Elastomer)	Yes
PS.G.57	Okonite	Power Cable, 600 V	1/c #2-7XCC-0.045 X-Olene FMR 600 V	Yes
PS.G.58	ASCO	Valve, Solenoid (Normally De-energized and Energized During Accident)	NP8316, 8320 Series (EPDM Elastomer)	Yes
PS.G.59	Gems Delaval	Level Transmitter	XM54854	Yes
PS.G.60	Rome and Okonite	Cable (Control and Instrumentation)	PVC Insulated, PVC Jacketed Cable	Yes
PS.G.64	Rockbestos	Cable (Instrumentation and Control, Extension)	Firewall III Chemically Cross-Linked Polyethylene Wire	Yes
PS.G.65	Rockbestos	Cable (Instrumentation and Control, Extension)	Firewall III Irradiation Cross-Linked Polyethylene Wire	Yes
PS.G.8	Namco	Limit Switches	EA180-14302, EA180-15302	Yes

Section 4.0 References

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16. NUREG/CR-5704 (ANL-98/31), “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,” U. S. Nuclear Regulatory Commission, April 1999.

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22. NRC Letter, “Acceptance for Referencing of Topical Report WCAP-14535-A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination”“, To: Sushil C. Jain, Division Vice President, From: Brian W. Sheron, Director, Dated September 12, 1996.

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APPENDIX A

FSAR SUPPLEMENT

APPENDIX A
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A1.0 APPENDIX A INTRODUCTION

The application for a renewed operating license is required by 10 CFR 54.21(d) to include an FSAR Supplement. This appendix provides that supplement for the PBNP FSAR. This appendix also includes FSAR content changes that are to be inserted into applicable existing FSAR sections that discuss the same subject as the TLAA covered in Section 4 of this application. Content changes are also being made to some FSAR sections to reflect the requirements of Aging Management Programs.

A2.0 CHANGES TO EXISTING FSAR CHAPTERS

CHAPTER 1 INTRODUCTION AND SUMMARY

Section 1.3 GENERAL DESIGN CRITERIA

Section 1.3.6 REACTOR COOLANT PRESSURE BOUNDARY (GDC 33 - GDC 36)

Add the following text after the third paragraph on Page 1.3-13.

See Section 15.4.1 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2.

Section 1.4 QUALITY ASSURANCE PROGRAM

Revise text as shown (page 1.4-2)

To the extent required by ANSI N18.7-1976 as hereinafter specifically noted, PBNP hereby commits to the above standards. Table 1.4-1 provides further information regarding commitments to regulatory guides and related standards.

For details of the Quality Assurance requirements for the Aging Management Programs implemented in accordance with 10 CFR 54 see Chapter 15.

PBNP is committed to the Point Beach Security and Safeguards Contingency Plan (SSCP). This plan meets or exceeds the requirements of ANSI N18.17, Industrial Security for Nuclear Power Plants.

CHAPTER 4 REACTOR COOLANT SYSTEM

Section 4.1 Design Basis

DESIGN CHARACTERISTICS

Cyclic Loads

Revise text as shown (page 4.1-9) Clearly, it is difficult to discuss in absolute terms, the transients that the plant will actually experience during the ~~40~~ 60 year~~s~~ operating life. For clarity, however, each transient condition is discussed in order to make clear the nature and basis for the various transients.

Heatup Cooldown

Revise as shown (page 4.1-9)

The number of such complete heatup and cooldown operations is specified at 200 times ~~each which corresponds to five such occurrences per year~~ for the ~~40~~ 60 year plant ~~design~~ life. For the ideal plant, only one heatup and one cooldown would occur ~~per 100% full power year~~ fuel cycle, i.e., the period between refuelings. In practice, experience to date indicates that, during the first year or so of operation, additional unscheduled plant cooldowns may be necessary for plant maintenance.

Unit Loading and Unloading

The unit loading and unloading cases are conservatively represented by a continuous and uniform ramp power change of 5% per minute between no load and full load. The reactor coolant temperature will vary with load as prescribed by the temperature control system. The number of each operation is specified ~~at 14,500 times or once per day~~ in Table 4.1-8 for the ~~40~~ 60 year plant ~~design~~ life. In practice, the plant is generally operated at base load conditions with changes in power at a rate much less than 5% per minute.

Revise the text as shown on Page 4.1-10

Step Increase and Decrease of 10%

The number of each operation is specified at 2000 times ~~or 50 per year~~ for the ~~40~~ 60 year plant ~~design~~ life.

Large Step Decreases in Load

This transient applies to a step decrease in turbine load of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature will automatically initiate a condenser steam dump system to avert a reactor shutdown or lifting of steam generator safety valves. The number of occurrences of this transient is specified at 200 times ~~or 5 per year~~ for the ~~40~~ 60 year plant ~~design~~ life. The operating experience of Point Beach Nuclear Plant Units 1 and 2 also indicates that this basis is adequately conservative.

Revise the text as shown on Page 4.1-11

Reactor Trip From Full Power

The number of occurrences of this transient is specified at 400 times ~~or 10 per year~~ for the ~~40~~ 60 year plant ~~design~~ life. The tripping history of Point Beach Nuclear Plant Units 1 and 2 indicate that this basis is indeed conservative.

Revise the text as shown on Page 4.1-13

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 ~~40~~ 60 year ~~design~~ life. These operating conditions include the cyclic application of pressure loadings and thermal transients. The number of thermal and loading cycles used for design purposes are listed in Table 4.1-8.

<u>Cyclic Loads</u>

Delete this table (page 4.1-22):

~~TABLE 4.1-8~~

~~THERMAL AND LOADING CYCLES~~

~~Transient Condition~~		~~Design Cycles*~~
~~1.~~	~~Plant heatup at 100°F per hour~~	~~200 (5/yr)~~
~~2.~~	~~Plant cooldown at 100°F per hour~~	~~200 (5/yr)~~
~~3.~~	~~Plant loading at 5% of full power per minute~~	~~14,500 (1/day)~~
~~4.~~	~~Plant unloading at 5% of full power per minute~~	~~14,500 (1/day)~~
~~5.~~	~~Step load increase of 10% of full power (but not to exceed full power)~~	~~2,000 (1/week)~~
~~6.~~	~~Step load decrease of 10% of full power~~	~~2,000 (1/week)~~
~~7.~~	~~Step load decrease of 50% of full power~~	~~200 (5/year)~~
~~8.~~	~~Reactor trip and attendant temperature transients~~	~~400 (10/year)~~
~~9.~~	~~Hydrostatic test, pressure 3110 psig temperature 100°F~~	~~5 (pre-operational)~~
~~10~~	~~Hydrostatic test, pressure 2485 psig temperature 400°F~~	~~94 (post-operational)~~
~~11.~~	~~Primary-to-secondary leak test (2250 psig)~~	~~27~~
~~12.~~	~~Secondary-to-primary leak test~~	~~128~~
~~13.~~	~~Steady state fluctuations - The reactor coolant average temperature for purposes of design is assumed to increase and decrease a maximum of 6°F in one minute. The corresponding reactor coolant pressure variation is less than 100 psig. It is assumed that an infinite number of such fluctuations will occur.~~	

~~* Estimated for equipment design purposes (40 year life) and not intended to be an accurate representation of actual transient or to reflect actual operating experience.~~

Power Uprate Project Point Beach Nuclear Plant Units 1 and 2, Volume 1, NSSS and BOP Licensing Report Additional Licensing Documentation, Westinghouse and Stone and Webster, April 2002

Addendum to the Stress Reports for the Point Beach Unit Nos. 1 and 2 Reactor Vessels, Westinghouse, August 1995

Add this table (Page 4.1-22):

TABLE 4.1-8

THERMAL AND LOADING CYCLES

Transient Condition		Design Cycles*
1.	Plant heatup at 100°F per hour	200
2.	Plant cooldown at 100°F per hour	200
3.	Plant loading at 5% of full power per minute	18,300 (for all components except pressurizer which is 11,680, Unit 1 Reactor Pressure Vessel is 14,500)
4.	Plant unloading at 5% of full power per minute	18,300 (for all components except pressurizer which is 11,680, Unit 1 Reactor Pressure Vessel is 14,500)
5.	Step load increase of 10% of full power (but not to exceed full power)	2,000
6.	Step load decrease of 10% of full power	2,000
7.	Step load decrease of 50% of full power	200
8.	Steady State Fluctuations Initial Fluctuations (+ 3°F and + 25 psi) Random Fluctuations (+ 0.5°F and + 6 psi)	 1.5×10^5 5×10^6
9.	Feedwater cycling at hot stand-by	2000 Reactor vessel 25,000 (Unit 1 - for other components) 10,000 (Unit 2 - for other components)
10.	Boron concentration equilibrium	23,360
11.	Loss of load	80
12.	Loss of Power	40
13.	Loss of flow in one loop	80
14.	Reactor trip and attendant temperature transients	400
15.	Inadvertent auxiliary spray	10
16.	Turbine roll test	10

TABLE 4.1-8

THERMAL AND LOADING CYCLES

Transient Condition		Design Cycles*
17.	Hydrostatic test, pressure 3110 psig temperature 100°F	5 (pre-operational)
18.	Hydrostatic test, pressure 2485 psig temperature 400°F	94 (post-operational)
19.	Primary-to-secondary leak test (2250 psig)	27
20.	Secondary-to-primary leak test	128

* Estimated for equipment design purposes (60 year life) and not intended to be an accurate representation of actual transients or to reflect actual operating experience. These cycles also assume a power uprate.

Section 4.2 RCS System Design And Operation

Reactor Coolant Pumps

... A fracture mechanics evaluation was made on the reactor coolant pump flywheel. This evaluation considered the following assumptions:

1. Maximum tangential stress at an assumed overspeed of 125%.
2. A crack through the thickness of the flywheel at the bore.
3. 400 cycles of startup operation in 40 years.

Using critical stress intensity factors and crack growth data attained on flywheel material, the critical crack size for failure was greater than 17 inches radially and the crack growth data was 0.030 in. to 0.060 in. per 1000 cycles. Ultrasonic examination techniques which are capable of detecting and sizing flaws smaller than the critical flaw size of the flywheel fracture analysis are utilized for the inspection of the flywheel. Based on the above information and the inspections outlined in the ISI Long-Term Plan, the intent of Regulatory Guide 1.14 is satisfied.

Add following text after above on page 4.2-9

An additional stress and fracture evaluation was completed in November 1996 (WCAP -15435-A). The evaluation assumed a leak before break limitation on the maximum pump speed and 6000 cycles of reactor coolant pump starts and stops for a 60 year service life. The estimated radial crack extension was shown to be negligible even when assuming a large initial crack length. See Section 15.4.3 for further License Renewal information.

Materials of Construction

Prior to the initial plant operation, the Nil-Ductility Transition Temperature (NDTT) of the reactor vessel plate or forging material opposite the core was established at a Charpy V-notch test value of 30 ft-lb or greater. The material was tested to verify conformity to specified requirements and to determine the actual NDTT value. In addition, this plate was 100% volumetrically inspected by ultrasonic testing using both longitudinal and shear wave methods.

Subsequently, the NRC issued 10 CFR 50.60, “Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation,” and Appendix G to Part 50, “Fracture Toughness Requirements.” These regulations imposed an additional requirement applicable to Point Beach that the Charpy upper-shelf energy of reactor vessel beltline materials must be maintained no less than 50 ft-lb throughout the life of the vessel, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of the ASME Code. Topical reports BAW-2178PA[(8)] and BAW-2192PA[(9)] were issued by the B&W Owners Group Reactor Vessel Working Group in April, 1994 and are applicable to Point Beach Units 1 and 2. These reports demonstrate that the Point Beach Units 1 and 2 reactor vessel beltline welds fabricated by Babcock & Wilcox provide margins of safety against fracture equivalent to those required by Appendix G of the ASME Code through the end of their respective Operating Licenses.

Insert the following paragraph (page 4.2-14):

See Section 15.4.1 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2.

Section 4.3 System Design Evaluation

SAFETY FACTORS

Reactor Vessel

Appendix G to 10 CFR 50 establishes requirements for the fracture toughness of the reactor vessel pressure boundary which provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences, to which the pressure boundary may be subjected over its service lifetime. Section IV.A.2 of Appendix G requires that the reactor vessel be operated with pressure-temperature limits at least as conservative as those obtained by following the methods of analysis and the required margins of safety of Appendix G of ASME Code Section XI.

Insert the following paragraph (Page 4.3-1):

See Section 15.4.1 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2.

Revise the following table as shown (Page 4.3-6) Power Uprate Project Point Beach Nuclear Plant Units 1 and 2, Volume 1, NSSS and BOP Licensing Report Additional Licensing Documentation, Westinghouse and Stone and Webster, April 2002

Addendum to the Stress Reports for the Point Beach Unit Nos. 1 and 2 Reactor Vessels, Westinghouse, August 1995

TABLE 4.3-1

SUMMARY OF PRIMARY PLUS SECONDARY STRESS INTENSITY

FOR COMPONENTS OF THE REACTOR VESSEL

Area	Stress Intensity (psi)	Allowable Stress 3 Sm (psi) (Operating Temperature)
Control Rod Housing	~~30,100~~ 45,700	~~70,000~~ 69,900
Head Flange	~~69,400~~ 70,000	~~80,000~~ 80,100
Vessel Flange	~~51,000~~ 67,400	~~80,000~~ 80,100
Closure Studs	~~104,000~~ 109,300	~~108,900~~ 118,800
Primary Nozzle	~~35,800~~ 48,800	~~80,000~~ 80,100
Vessel Support	~~24,900~~ 41,200	~~80,000~~ 80,100
Core Support Pad	~~22,100~~ 57,500	~~*34,900 (1.5 Sm)~~ 69,900
Bottom Head to Shell	~~30,800~~ 28,600	~~80,000~~ 80,100
Bottom Instrumentation	~~10,900~~ 57,800	~~70,000~~ 69,900
Safety Injection Nozzle	~~50,900~~ 46,800	~~80,000~~ 80,100
Vent Nozzle	25,900	69,900
Vessel Wall Transition	32,200	80,100
Head Adapter Plugs	27,600	48,000

~~* Primary limit is shown here because there is no significant secondary effect.~~

Revise the following table-(Page 4.3-7)Power Uprate Project Point Beach Nuclear Plant Units 1 and 2, Volume 1, NSSS and BOP Licensing Report Additional Licensing Documentation, Westinghouse and Stone and Webster, April 2002

Addendum to the Stress Reports for the Point Beach Unit Nos. 1 and 2 Reactor Vessels, Westinghouse, August 1995

TABLE 4.3-2
SUMMARY OF CUMULATIVE (60 year) FATIGUE USEAGE FACTORS FOR COMPONENTS OF THE REACTOR VESSEL

Item	Usage factor*[a]
Control Rod Housing	~~0.000~~ 0.293
Head Flange	~~0.029~~ 0.015
Vessel Flange	~~0.016~~ 0.945
~~Stud Bolts~~ Closure Studs	~~0.511~~ 0.930
Primary Nozzles	0.155
Vessel Support	~~0.020~~ 0.995
Core Support Pad ~~(lateral)~~	~~0.000~~ 0.731
Bottom Head to Shell	~~0.000~~ 0.004
Bottom Instrumentation	~~0.000~~ 0.384
Safety Injection Nozzle	~~0.470~~ 0.200
Vent Nozzle	0.000
Vessel Wall Transition	0.004
Head Adapter Plugs	0.002

* Covers all transients

[a] As defined in the applicable Edition of Section III of the ASME Boiler and Pressure Vessel Code, Nuclear Vessels

Section 4.4 Tests And Inspections

REACTOR COOLANT SYSTEM INSPECTION

Nondestructive Inspection of Material and Components Prior to Operation

A reactor pressure vessel surveillance program in accordance with the requirements of 10 CFR Part 50, Appendix H (Reactor Vessel Material Surveillance Program Requirements) and ASTM E 185-82 (Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels) has been implemented for the Point Beach

Nuclear Plant to obtain information on the effects of irradiation on the reactor pressure vessel material under operating conditions. The program consists of periodically testing irradiated reactor vessel material specimens at intervals defined in E 185-82 and comparing the data with preirradiation data to establish the shift in RT_{NDT}. This information may be used in the development of reactor coolant system pressure-temperature limits and to demonstrate compliance with 10 CFR 50.60 (Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation) and 50.61 (Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events).

Insert the following paragraph: (page 4.4-1).

See Section 15.4.1 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2.

Revise table as shown (Page 4.4-13)

TABLE 4.4-3

POINT BEACH NUCLEAR PLANT, UNIT 2

REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL SCHEDULE

Capsule Letter	Approximate Removal Date*
V	November 1974 (actual)
T	March 1977 (actual)
R	April 1979 (actual)
S	October 1990 (actual)
P	June 1997 (actual)
N	Standby
A	April 2022**

*The actual removal dates will be adjusted to coincide with the closest scheduled plant refueling outage or major reactor plant shutdown.

** The actual removal date will be adjusted depending on the implementation of a Power Uprate and operating history of Unit 2.

CHAPTER 5 CONTAINMENT SYSTEMS

SECTION 5.1 CONTAINMENT SYSTEM STRUCTURE

Section 5.1.2 CONTAINMENT SYSTEM STRUCTURE DESIGN

Section 5.1.2.2 MECHANICAL DESIGN BASES

Liner Plate Criteria

Revise Text as shown (page 5.1-30)

The following fatigue loads are considered in the design of the liner plate:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is ~~40~~ 60 cycles for the plant life of ~~40~~ 60 years.
2. Thermal cycling due to containment interior temperature varying during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500 cycles.
3. Thermal cycling due to the design basis accident is assumed to be one cycle. 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 plant life.

Prestress Losses

Revise text as shown (page 5.1-61) Assuming that the jacking stress for the tendons is 0.8 f'_S or 192,000 psi and using the assumed prestress loss parameters, the following tabulation shows the magnitude of the design losses and the final effective prestress at end of ~~40~~ 60 years for a typical dome, hoop, and vertical tendon.

Section 5.6.2.6 MISCELLANEOUS MATERIALS OF CONSTRUCTION

Revise text as shown (page 5.6-16).

4. Power and Instrumentation Cable

Power and instrumentation cables have been subjected to the following series of tests and have shown acceptable performance.

a. Thermal aging of the cable. ~~to simulate 40 effective full power years. (~~The EQ program will manage thermal aging, as described in Chapter 15.)

b. Exposure to radiation ranging up to 2.0 x 10^{8} rads.

c. Exposure to temperature, steam and chemical environment simulating post accident conditions.

SECTION 5.7 TESTS AND INSPECTIONS

Section 5.7.1.5 TENDON SURVEILLANCE

Revise text as shown (page 5.7-5)

The inspection intervals, measured from the date of the initial proof test, are as follows:

One year from initial testing;

Three years from initial testing; and

Every five years thereafter.

The Pre-Stressed Concrete Containment Tendon Surveillance Program Section (15.3.1) contains additional provisions for the period of extended operation.

CHAPTER 7 INSTRUMENTATION AND CONTROL

Section 7.6 INSTRUMENTATION SYSTEMS

Section 7.6.1 NUCLEAR INSTRUMENTATION SYSTEM

Section 7.6.1.2 System Design

b. Wide-range Neutron Detector

Revise the following paragraph as shown (page 7.6-7)

Equipment for the wide-range channel includes the detector assembly and in-containment cable assembly, an amplifier cable assembly (from containment penetration to pre-amplifier), a pre-amplifier, a signal processor, and an output expansion module. The detector and cable assemblies are environmentally qualified for operation in a harsh containment environment. All electrical equipment is seismically supported. The channel is designed to operate under normal conditions and to survive a loss-of-coolant accident, providing reliable flux measurement before, during, and after an accident. The qualification of this equipment (detector and cable assemblies only) will be maintained during the period of extended operation by the EQ Program.

Revise the following paragraph as shown (page 7.6-8)

The wide range detection channel is environmentally qualified for operation in a harsh environment (detector and cable assemblies only). All electrical equipment is seismically supported. The system is designed to operate under normal conditions and to survive a loss-of-coolant accident (LOCA) environment, providing reliable measurement before, during, and after the LOCA. The qualification of this equipment (detector and cable assemblies only) will be maintained during the period of extended operation by the EQ Program.

CHAPTER 9 AUXILIARY AND EMERGENCY SYSTEMS

Section 9.1.4 REQUIRED PROCEDURES AND TESTS

Revise text as shown (page 9.1-7)

The active components of the component cooling system are in either continuous or intermittent use during normal plant operation. Periodic visual inspections and preventive maintenance can be conducted as necessary without interruption of cooling system operation. The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document. The Closed-Cycle Cooling Water System Surveillance Program (Section 15.2.9) will be implemented during the period of extended operation.

SECTION 9.6 SERVICE WATER SYSTEM (SW)

Section 9.6.4 REQUIRED PROCEDURES AND TESTS

Revise text as shown (page 9.6-5)

The SW system components are tested and inspected in accordance with Technical Specification surveillance criteria and frequencies. Testing verifies motor-driven pump operability, and operability of all required valves.

The passive portions of the system are monitored in accordance with the Open-Cycle Cooling (Service) Water System Surveillance Program (Section 15.2.14) during the period of extended operation.

SECTION 9.10 FIRE PROTECTION SYSTEM

Section 9.10.1 Design Basis

Revise text as shown (page 9.10-1)

The fire protection program is outlined in the Fire Protection Evaluation Report (FPER) and additional provisions in Section 9.10.2. The purpose of the FP system is to provide assurance, through defense-in-depth design, that a fire will not prevent the performance of necessary safe shutdown functions or significantly increase the risk of radioactive release to the environment during a postulated fire. The FP program consists of fire detection, extinguishing systems and equipment, administrative controls and procedures, and trained personnel.

Section 9.10.2 System Design and Operation

Revise text as shown (page 9.10-2)

In order to meet the requirements of the facility operating license, Wisconsin Electric implements and maintains in effect all provisions of the approved fire protection program as described in the Point Beach Fire Protection Evaluation Report (FPER). Additional commitments are contained in Wisconsin Electric to NRC submittals dated November 1, 1976, June 20, 1977, November 7, 1977, January 13, 1978, February 1, 1978, February 14, 1978, March 15, 1978, September 22, 1978, December 29, 1978, September 26, 1979, December 20, 1979, June 23, 1980, October 13, 1980, February 7, 1986, and February 29, 1988. These submittals were approved in an NRC safety evaluation report dated August 2, 1979 and its supplements dated October 21, 1980, January 22, 1981, and July 27, 1988, and July 18, 1995.

Additional provisions are provided for the period of extended operation in the Fire Protection Program outlined in Section 15.2.10.

CHAPTER 11 RADIATION MONITORING AND WASTE DISPOSAL

Section 11.0 DESCRIPTION AND SUMMARY

Revise the following table as shown (page 11.0-2)

TABLE 11.0-1
WASTE DISPOSAL SYSTEM
PERFORMANCE DATA

~~Plant Design Life~~	~~40 years~~
Normal process capacity, liquids	35 gpm
Evaporator load factor[1]	43%
Annual liquid discharge	
Volume (2 units)	444,920 gal.
Activity	
Tritium (2 units)	1200 curies
Other (2 units)	1.0 curies
Annual gaseous discharge	
Activity (2 units)	1,100 curies
Annual solids prepared for burial shipment (2 units)	
Volume, (55 gallon units)	~700
(spent resin)	~1000 ft^3

[1] batch operation

CHAPTER 14 SAFETY ANALYSIS

Section 14.2.3 Accidental Release-Waste Gas

Revise text as shown (page 14.2.3-5)

This discussion is provided for historical purposes. The cyrogenic system was never used, and is not operational. Major portions of the system have been abandoned in place. Thus the reference to a 40-year operating period would still bound a 60-year plant operating period.

The noble gases absorbed in the cryogenic absorber vessel can be desorbed at the end of each 180 day cryogenic cycle and stored in one of the existing gas decay tanks. The resulting activity would, if accumulated over a 40-year period in this single gas decay tank, reach a maximum value of 50,000 curies Krypton-85. Xenon-133 would reach a maximum value of 2,100 curies. The whole body dose resulting from an instantaneous release of the gas decay tank contents would be 0.7 rem, which is less than that described previously for a single gas decay tank rupture.

Section 14.3.3 Core and Internals Integrity Analysis

Baffle Former Bolt Replacement (Unit 2 Only)

Revise text as shown (page 14.3.3-6) Point Beach Unit 2 was selected as a lead plant to collect information regarding a baffle former bolt cracking phenomena observed in some foreign nuclear power plants. All baffle former bolts were inspected and a select pattern of baffle former bolts were replaced using methodology presented WCAP-15133 “Determination of Acceptable Baffle-Barrel-Bolting for Point Beach UNITS 1 and 2.” This replacement also included one bolt in a “non-critical” location which was removed and not replaced. WCAP-15133 was based on an NRC accepted methodology presented in WCAP 15029 “Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions.” This methodology and its use were strictly limited to the baffle former bolt project. (Reference 3 through 6)

The Aging Management Program, Reactor Vessel Internals Program (Section 15.2.17) provides additional information for monitoring during the period of extended operation.

NEW FSAR CHAPTER 15

FSAR Section 15 has been selected for the location of Aging Management Program related information. Section 15.2 of this appendix contains a summary description of the programs for managing the effects of aging during the period of extended operation. Time-limited aging analyses (TLAA) supporting activity summaries are contained in Section 15.3 of this appendix. Section 15.4 of this appendix contains a summary of the evaluation of (TLAAs) for the period of extended operation.

15.1 PROGRAMS THAT MANAGE THE EFFECTS OF AGING AND GENERIC QUALITY ASSURANCE PROGRAM REQUIREMENTS

This section provides summaries of the programs and activities credited for managing the effects of aging. These aging management programs may not exist as discrete programs at PBNP. In many cases they exist as a compilation of various implementing documents that, when taken as a whole, satisfy the intent of NUREG-1800 and/or NUREG-1801 elements. The Program Basis Documents for License Renewal provide and describe the program's structure, including a compilation of all required implementing documents. The implementing documents are identified in and are referenced to the applicable program basis document(s).

The PBNP Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2 of NUREG-1800, Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants, published July 2001. The elements of corrective action, confirmation process, and administrative controls in the Quality Assurance Program are applicable to both safety related and non-safety related systems, structures, and components that are subject to an aging management review. Generically, these three elements are applicable as follows:

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

Administrative Controls

Aging management programs are implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

15.2 AGING MANAGEMENT PROGRAMS

The description of the PBNP Aging Management Programs are consistent with their status as configured to apply to the period of extended operation.

15.2.1 ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program

ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (ISI) Program inspections are performed to identify and correct degradation in Class 1, 2, and 3 piping, components and their integral attachments. The program includes periodic visual, surface and/or volumetric examinations and leakage tests of all Class 1, 2 and 3 pressure-retaining components, and their integral attachments, including welds, pump casings, valve bodies, and pressure-retaining bolting. These components and their integral attachments are identified in ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” or commitments requiring augmented inservice inspections, and are within the scope of license renewal. This program is in accordance with 10 CFR 50.55a and approved Code Cases and Relief Requests.

15.2.2 ASME Section XI, Subsections IWE & IWL Inservice Inspection Program

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program manages aging of (a) steel liners of concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets and moisture barriers; and pressure retaining bolting, and (b) reinforced concrete containments and unbonded post-tensioning systems. The primary inspection methods employed are visual examinations with limited supplemental volumetric and surface examinations, as necessary. Tendon anchorages and wires are visually examined. Tendon wires are tested to verify that minimum mechanical property requirements are met. Tendon corrosion protection medium is analyzed for alkalinity, water content and soluble ion concentrations. Prestressing forces are measured in sample tendons. Measured tendon lift-off forces are compared to predicted tendon forces calculated in accordance with Regulatory Guide 1.35.1. This program is in accordance with 10 CFR 50.55a and approved Code Cases and Relief Requests.

This program manages aging effects for:

(1) Carbon steel and miscellaneous polymeric materials and components that provide containment pressure boundary/leak-tight barrier function and are tested/inspected in accordance with 10 CFR 50, Appendix J and/or ASME Section XI, Subsection IWE,

(2) Containment tendons, and

(3) Concrete, which is inspected in accordance with ASME Section XI, Subsection IWL.

15.2.3 ASME Section XI, Subsection IWF Inservice Inspection Program

The ASME Section XI, Subsection IWF Inservice Inspection Program manages aging effects for Class 1, 2, and 3 component supports. The primary inspection method employed is visual examination. Criteria for acceptance and corrective action are in accordance with ASME Section XI, Subsection IWF. Degradation that potentially compromises the function or load capacity of the support, including bolting, is identified for evaluation. Supports requiring corrective action are re-examined during the next inspection period. This program is in accordance with 10 CFR 50.55a and approved Code Cases and Relief Requests.

15.2.4 Bolting Integrity Program

The Bolting Integrity Program manages the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Section XI related bolting and generic guidance regarding material selection, thread lubrication and assembly of bolted joints. The program considers the guidelines delineated in NUREG-1339 for a bolting integrity program, EPRI NP-5769 (Reference 5) (with the exceptions noted in NUREG-1339) for safety related bolting, and EPRI TR-104213 (Reference 6) for non-safety related bolting. The Bolting Integrity Program credits seven separate aging management programs for the inspection of bolting. The seven aging management programs are: (1) ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program, (2) ASME Section XI, Subsections IWE & IWL Inservice Inspection Program, (3) ASME Section XI, Subsection IWF Inservice Inspection Program, (4) Systems Monitoring Program, (5) Structures Monitoring Program, (6) Reactor Vessel Internals Program, and (7) the Periodic Surveillance and Preventive Maintenance Program.

15.2.5 Boraflex Monitoring Program

The Boraflex Monitoring Program manages aging effects for the boraflex material in the spent fuel racks. This program provides for blackness testing and areal density measurements of the boraflex material in the spent fuel storage racks to confirm the in-service boraflex performance. In addition, tracking of the spent fuel pool silica levels provides a qualitative indication of boron carbide loss. The results of silica sampling will be trended and analyzed using a predictive code. Neutron attenuation or blackness testing will be performed to determine gap formation, while areal density measurements will be used to ascertain the physical loss of boron carbide. Monitoring and analysis of criticality will also be performed to assure that the required 5% subcriticality margin is maintained. Based on the results of these inspections and analysis, appropriate measures will be taken to ensure the boraflex will continue to perform its intended function. This program addresses the concerns described in NRC GL 96-04.

15.2.6 Boric Acid Corrosion Program

The Boric Acid Corrosion Program manages aging effects for structures and components as a result of borated water leakage. The program requires periodic visual inspection of systems that contain borated water for evidence of leakage or accumulations of dried boric acid. It includes provisions for (a) determination of the principal location or source of the leakage, (b) examination requirements and procedures for locating small leaks, and (c) evaluations and/or corrective actions to ensure that boric acid leakage does not lead to degradation of the leakage source as well as other SSC exposed to the leakage, including mechanical, structural, and electrical items such as bolts, fasteners, piping, cables, cable trays, electrical connectors, etc., which could cause the loss of intended function(s). This program complies with PBNP’s response to NRC GL 88-05.

15.2.7 Buried Services Monitoring Program

The Buried Services Monitoring Program manages aging effects on the external surfaces of carbon steel, low-alloy steel, and cast iron components (e.g., tanks, piping) that are buried in soil or sand. This program includes (a) preventive measures to mitigate degradation (e.g., external coatings and wrappings), and (b) visual inspections of external surfaces of buried components for evidence of coating damage and substrate degradation to manage the effects of aging. The periodicity of these inspections will be based on plant operating experience and opportunities for inspection such as scheduled maintenance work.

15.2.8 Cable Condition Monitoring Program

The Cable Condition Monitoring Program manages aging of conductor insulation materials on cables and connectors, and other electrical insulating materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The scope of this program includes accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal. The program requires (a) visual inspection of a representative sample of accessible electrical cables and connections in adverse localized environments once every 10 years for evidence of jacket surface degradation, (b) testing of nuclear instrumentation circuits once every 10 years to detect a significant reduction in cable insulation resistance, and (c) testing of a representative sample of in-scope, medium-voltage cables not designed for submergence subject to prolonged exposure to significant moisture and significant voltage once every 10 years to detect deterioration of insulation.

15.2.9 Closed-Cycle Cooling Water System Surveillance Program

The Closed-Cycle Cooling Water System Surveillance Program manages aging effects in closed cycle cooling water systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink. The program includes (a) maintenance of system corrosion inhibitor concentrations to minimize degradation, and (b) periodic or one-time surveillance testing and inspections to evaluate system and component performance. Inspection methods may include visual, ultrasonic (UT) and eddy current (ECT) testing.

15.2.10 Fire Protection Program

The Fire Protection Program includes (a) fire barrier inspections, (b) electric and diesel-driven fire pump tests, (c) periodic inspection and testing of the halon fire suppression system, and (d) periodic maintenance, testing, and inspection of water-based fire protection systems. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed to ensure that functionality and operability is maintained. Periodic testing of the electric and diesel-driven fire pumps ensures that an adequate flow of firewater is supplied and that there is no degradation of diesel fuel supply lines. Periodic maintenance, testing and inspection activities of water-based fire protection systems provides reasonable assurance that fire water systems are capable of performing their intended function. Inspection and testing is performed in accordance with the nuclear insurance carrier's fire protection system testing requirements and generally follows the guidance of applicable NFPA Codes and Standards, as described in the PBNP Fire Protection Evaluation Report.

15.2.11 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion Program manages aging effects due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The program implements the EPRI guidelines in NSAC-202L-R2 (Reference 7) for an effective FAC program and includes (a) an analysis using a predictive code such as CHECWORKS to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm the predictions, and (d) repairing or replacing components, as necessary.

15.2.12 Fuel Oil Chemistry Control Program

The Fuel Oil Chemistry Control Program mitigates and manages aging effects on the internal surfaces of fuel oil storage tanks and associated components in systems that contain fuel oil. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) periodic or conditional visual inspection of internal surfaces or wall thickness measurements (e.g., by UT) from external surfaces of fuel oil tanks, and (d) one-time inspections of a representative sample of components in systems that contain fuel oil.

15.2.13 One-Time Inspection Program

The One-Time Inspection Program addresses potentially long incubation periods for certain aging effects and provides a means of verifying that an aging effect is either not occurring or progressing so slowly as to have negligible effect on the intended function of the structure or component. Hence, the One-Time Inspection Program provides measures for verifying an aging management program is not needed, verifying the effectiveness of an existing program, or determining that degradation is occurring which will require evaluation and corrective action.

The program elements include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The inspection sample includes locations where the most severe aging effect(s) would be expected to occur. Inspection methods may include visual (or remote visual), surface or volumetric examinations, or other established NDE techniques.

This program is used for the following:

- To verify the effectiveness of water chemistry control for managing the effects of aging in stagnant or low-flow portions of piping, or occluded areas of components, exposed to a treated water environment.
- To manage the aging effects of loss of material due to galvanic corrosion and selective leaching.
- To manage aging effects in infrequently accessed areas, such as high radiation, high temperature, confined spaces, and submerged areas.
- To verify the effectiveness of fuel oil chemistry control for managing the effects of aging of various components in systems that contain fuel oil.
- To verify aging effects are not occurring in various components (e.g., reactor vessel internals hold-down spring, letdown orifices, steam traps, and miscellaneous heat exchangers).

15.2.14 Open-Cycle Cooling (Service) Water System Surveillance Program

The Open-Cycle Cooling (Service) Water System Surveillance Program manages aging effects caused by exposure of internal surfaces of metallic components in water systems (e.g., piping, valves, heat exchangers) to raw, untreated (e.g., service) water. The aging effects are managed through (a) surveillance and control of biofouling, (b) verification of heat transfer by testing, and (c) routine inspection and maintenance program activities to ensure that aging effects do not impair component intended function. Inspection methods include visual, ultrasonic (UT), eddy current (ECT), and Tangential Radiography. This program complies with PBNP’s response to NRC GL 89-13.

15.2.15 Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program manages aging effects for certain SSCs within the scope of license renewal. The program provides for inspection, examination, or testing of selected structures and components, including fasteners, for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or code requirements). Additionally, the program provides for replacement of certain components on a specified frequency based on operating experience. The Periodic Surveillance and Preventive Maintenance Program is also used to verify the effectiveness of other aging management programs.

15.2.16 Reactor Coolant System Alloy 600 Inspection Program

The Reactor Coolant System Alloy 600 Inspection Program manages crack initiation and growth due to PWSCC of RCS pressure boundary nickel-based alloy components (e.g., Alloy 600/690 reactor vessel/head penetration nozzles, Inconel 82/182, 82/152, and 52/152 weld joints). The program includes (a) PWSCC susceptibility assessment using industry models to identify susceptible components, (b) monitoring and control of reactor coolant chemistry to mitigate PWSCC, (c) inservice inspections (ISI) of reactor vessel/head penetrations and RCS pressure boundary welds in accordance with ASME Section XI, Subsection IWB, Table IWB 2500-1, and (d) augmented inspections or preemptive repair/replacement of susceptible components or welds.

15.2.17 Reactor Vessel Internals Program

The Reactor Vessel Internals Program manages the aging effects for reactor vessel internals. The program provides for (a) Inservice Inspection (ISI) in accordance with ASME Section XI requirements, including examinations performed during the 10-year ISI examination; (b) An evaluation that will identify leading locations with respect to IASCC and irradiation embrittlement, appropriate non-destructive examination techniques, and an examination schedule for these locations; (c) Baffle-former/barrel-former bolt evaluation that will determine the acceptability of the current arrangement or if ultrasonic examination and/or replacement of these bolts is necessary; (d) For cast austenitic stainless steel components subject to neutron fluence in excess of 10^{17} n/cm^2 or determined to be susceptible to thermal embrittlement, an augmented inspection of components experiencing significant tensile stress (>5 ksi); (e) Evaluation of the significance of void swelling; (f) monitoring and control of reactor coolant water chemistry in accordance with the Water Chemistry Control Program to mitigate SCC or IASCC; (g) Participation in industry initiatives that will generate additional data on aging mechanisms relevant to RVI and develop appropriate inspection techniques to permit detection and characterization of features of interest; and (h) One-time inspection of the internals hold-down spring for evidence of stress relaxation.

15.2.18 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program manages the aging effect reduction of fracture toughness due to neutron embrittlement of the low alloy steel reactor vessels. Monitoring methods will generally be in accordance with 10 CFR 50, Appendix H, but may also include direct measurement of fracture toughness specimens to support a Master Curve Approach. This program includes (a) capsule insertion, withdrawal and materials testing/evaluation, (including upper shelf energy and RT_{NDT} determinations), (b) fluence and uncertainty calculations, (c) monitoring of Effective Full Power Years (EFPY), (d) development of pressure-temperature limitations, and (e) determination of low-temperature overpressure protection (LTOP) setpoints. The program ensures the reactor vessel materials (a) meet the fracture toughness requirements of 10 CFR 50, Appendix G, and (b) have adequate margins against brittle fracture caused by Pressurized Thermal Shock (PTS) in accordance with 10 CFR 50.61; or alternatively, via the Master Curve Approach, which involves the use of directly measured fracture toughness data.

15.2.19 Steam Generator Integrity Program

The Steam Generator Integrity Program incorporates the guidance of NEI 97-06 and maintains the integrity of the steam generators, including tubes, tube plugs or other tube repairs, and various secondary-side internal components. The program manages aging effects through a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures. Component degradation is mitigated by controlling primary and secondary water chemistry. Eddy current testing is used to detect steam generator tube flaws and degradation. Visual inspections are performed to identify degradation of various secondary side steam generator internal components.

15.2.20 Structures Monitoring Program

The Structures Monitoring Program manages the aging effects associated with steel (including fasteners), concrete (including masonry block and grout), earthen berms, and elastomers. The environments include below grade and fluid exposed material, outdoor weather, and indoor air. The program includes all safety related buildings, structures within the containment, other buildings within the scope of license renewal, crane bridge and trolley structures, and component supports (including HELB structures, panels, etc.) within the scope of license renewal. The program provides for periodic visual inspections and examination of accessible surfaces of the structures and components and identifies the aging effects that impact the materials of construction.

15.2.21 Systems Monitoring Program

The Systems Monitoring Program manages aging effects for normally accessible, external surfaces of piping, tanks, and other components and equipment within the scope of license renewal. These aging effects are managed through visual inspection and monitoring of external surfaces for leakage and evidence of material degradation.

15.2.22 Tank Internal Inspection Program

The Tank Internal Inspection Program manages aging effects on the (a) internal surfaces of carbon steel tanks, and (b) inaccessible external surfaces of carbon steel tanks (i.e., tank bottoms) where wall thickness measurements may be taken from inside the tank to detect external degradation (e.g. using ultrasonic techniques).

This program provides for periodic inspections to confirm that aging effects will not impair tank intended functions. Tank wall thinning of internal surfaces may be detected by direct visual inspection from inside the tank or indirectly by UT wall thickness measurements from outside the tank. Tank wall thinning of external surfaces that are inaccessible (e.g., bottom of tanks that sit directly on the ground or other support structures) will be detected by UT wall thickness measurements from inside the tank.

15.2.23 Thimble Tube Inspection Program

The Thimble Tube Inspection Program manages aging effects for in-core instrument thimble tubes. This program requires periodic eddy current testing of thimble tubes and contains criteria for determining sample size, inspection frequency, flaw evaluation, and corrective action, in accordance with NRC Bulletin 88-09.

15.2.24 Water Chemistry Control Program

The Water Chemistry Control Program manages aging effects by controlling the internal environment of systems and components. Primary, borated and secondary water systems are included in the scope of the program. The program conforms to the guidelines in EPRI TR-105714 (Reference 8) and TR-102134 (Reference 9). The aging effects are managed by controlling concentrations of known detrimental chemical species such as halogens, sulfates and dissolved oxygen below the levels known to cause degradation. The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of water chemistry. For low-flow or stagnant portions of a system, a one-time inspection of selected components at susceptible locations provides verification of the effectiveness of the Water Chemistry Control Program. No verification inspections are required for intermediate and high flow regions.

15.3 TIME LIMITED AGING ANALYSIS SUPPORTING ACTIVITIES

15.3.1 Pre-Stressed Concrete Containment Tendon Surveillance Program

The Pre-Stressed Concrete Containment Tendon Surveillance Program is a confirmatory program that monitors the loss of containment prestressing forces in containment tendons throughout the life of the plant, including the period of extended operation. This program consists of an assessment of the results of the tendon prestressing force measurements performed in accordance with ASME Section XI, Subsection IWL. The assessment related to the adequacy of the prestressing forces will consist of the establishment of (a) acceptance criteria, and (b) trend lines. The acceptance criteria will normally consist of a predicted lower limit (PLL) and the minimum required prestressing force or value (MRV). The trend line represents the trend of prestressing forces based on actual measured forces. Maintaining the prestressing force trend lines above the PLL ensures that the prestressing forces in the containment would not be below the MRVs prior to the end of the period of extended operation. In accordance with the requirements of 10 CFR 50.55a(b)(2)(viii)(B), an evaluation will be performed if the trend lines predict the prestressing forces in the containment to be below the MRV before the next scheduled inspection.

15.3.2 Environmental Qualification Program

The Environmental Qualification (EQ) Program 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. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered time-limited aging analyses (TLAAs) for license renewal. The EQ Program ensures that these EQ components are maintained within the bounds of their qualification bases.

15.3.3 Fatigue Monitoring Program

The Fatigue Monitoring Program is a confirmatory program that monitors loading cycles due to thermal and pressure transients and cumulative fatigue usage for selected reactor coolant system and other component locations. The program provides an analytical basis for confirming that the actual number of cycles does not exceed the number of cycles used in the design analysis, and the cumulative fatigue usage will be maintained below the allowable limit during the period of extended operation.

The impact of the effects of reactor coolant environment on component fatigue life has been evaluated for a sample of critical components, including the seven component locations selected in NUREG/CR-6260. Appropriate environmental fatigue factors were calculated using the formulae from NUREG/CR-6583 for carbon and low-alloy steels and NUREG/CR-5704 for austenitic stainless steels. These critical component locations were determined to be acceptable for the period of extended operation, including the effects of reactor coolant environment. The acceptability of these critical component locations, including the effects of reactor coolant environment, will continue to be confirmed by the Fatigue Monitoring Program.

15.4 EVALUATION OF TIME-LIMITED AGING ANALYSES

As part of a License Renewal Application, 10 CFR 54.21(c) requires that an evaluation of time-limited aging analyses (TLAAs) for the period of extended operation be provided. The following TLAAs have been identified and evaluated to meet this requirement. These discussions are numbered and inserted into the FSAR sections where these subjects are covered.

15.4.1 Reactor Vessel Irradiation Embrittlement

The PBNP Units 1 and 2 reactor vessels are described in Chapters 3.0 and 4.0. Time-limited aging analyses (TLAAs) applicable to the reactor vessels are:

- Pressurized thermal shock
- Upper-shelf energy
- Pressure-temperature limits

The Reactor Vessel Surveillance Program manages reactor vessel irradiation embrittlement utilizing subprograms to monitor, calculate, and evaluate the time-dependent parameters used in the aging analyses for pressurized thermal shock, upper-shelf energy, and pressure-temperature limit curves to ensure continuing vessel integrity through the period of extended operation.

Reactor Vessel Pressurized Thermal Shock

The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock 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.

The calculated RT_{PTS} values at the end of life extension for the PBNP Units 1 and 2 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, with the exception of the Unit 2 RPV intermediated to lower shell circumferential weld.

The EOLE fluence yields an RT_{PTS} value of 316°F when using Charpy based methods for the limiting weld of the Unit 2 RPV. Therefore, to obtain extra margin relative to reaching EOLE, a bounding evaluation of Master Curve fracture toughness data was used to properly define a fracture toughness-based transition temperature (Reference 1). The additional fracture toughness testing and evaluation using the Master Curve approach provides a technically superior method for assessing radiation damage to the limiting PBNP-2 weld.

Use of the Master Curve methodology, extrapolated to EOLE fluence, shows that the RPV limiting weld metal meets PTS screening criteria out to EOLE and beyond. These projections will be confirmed by additional testing of weld heat 72442 from the B&W Owners Group MIRVP prior to reaching the EOL fluence at PBNP Unit 2. A supplemental surveillance program will be designed and implemented at PBNP Unit 2 that includes the limiting weld metal for future evaluation using the Master Curve methodology. The testing of this supplemental capsule at a fluence corresponding to EOLE will confirm the toughness condition for the PBNP Unit 2 RPV weld at about 38 EFPY, which is well before EOLE is reached.

The analysis associated with pressurized thermal shock has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

Reactor Vessel Upper-Shelf Energy

The requirements on reactor vessel Charpy upper-shelf energy are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G requires licensees to submit an analysis at least 3 years prior to the time that the upper-shelf energy of any reactor vessel material is predicted to drop below 50 ft-lb, as measured by Charpy V-notch specimen testing.

A 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 the end of life extension.

The analysis associated with upper-shelf energy has been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

Reactor Vessel Pressure/Temperature Limits

The requirements in 10 CFR 50, Appendix G, ensure that heatup and cooldown of the reactor pressure vessel are accomplished within established pressure-temperature limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel becomes embrittled and its fracture toughness is reduced, the allowable pressure is reduced.

Operation of the Reactor Coolant System is also limited by the net positive suction head curves for the reactor coolant pumps. These curves specify the minimum pressure required to operate the reactor coolant pumps. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G pressure-temperature limits and the reactor coolant pumps net positive suction head curves.

To address the period of extended operation, the end of license extension projected fluences, and the RPV material properties were used to determine the limiting materials, and calculate pressure-temperature limits for heatup and cooldown. When considering the master-curve ART for the Unit 2 intermediate to lower shell girth weld, the highest “Circ-Flaw” ART would then come from the PBNP Unit 1 intermediate to lower shell circumferential weld. The most limiting “Axial-Flaw” ART comes from the PBNP Unit 1 lower shell axial welds (for 1/4T) and the intermediate shell axial welds (for 3/4T).

The analysis associated with reactor vessel pressure-temperature limit curves has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

15.4.2 Fatigue

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as time limited aging analyses for the Point Beach Nuclear Plant. Specific components have been designed and analyzed considering transient cycle assumptions identified in vendor specifications and the PBNP FSAR.

In conjunction with revising the NSSS design transients for the Unit 2 Replacement Steam Generator Project (SGRP), and the Power Uprate Project (PUP), the NSSS design transients were also evaluated for acceptability for a 60-year operating period. The number of NSSS transients actually experienced by the two units was identified. Based on historical transient occurrences, and current plant operational practices, the number of future NSSS transients was forecasted for a 60-year operating period. With few exceptions, the anticipated number of transients for a 60-year operating period was far less than the original design number of transients for a 40-year operating period.

The exceptions noted above comprise a set of pressure test transients that were included in some of the NSSS component Equipment Specifications. The pressure test transients forecasted for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The NSSS design transient set was revised to include an increased number of pressure test transients, sufficient for a 60-year operating period.

In addition, the NSSS transient set was also revised to increase the number of steady state random RCS pressure and temperature fluctuations to ensure adequate margin existed for a 60-year operating period. The revised set of NSSS design transients were used in performing the detailed engineering evaluations in support of the Power Uprate Project.

Experience has shown, however, that actual plant operation is often very conservative with respect to the design transients. The use of actual operating history and transient monitoring data acquired by the FatiguePro Automatic Cycle Counting and Fatigue Monitoring System installed at Point Beach (Fatigue Monitoring Program) will allow quantification of the conservatism in the existing fatigue analysis and demonstrate that the design fatigue analyses will bound the extended period of operation. The PBNP Fatigue Monitoring Program is considered a confirmatory program.

<u>ASME Boiler and Pressure Vessel Code, Section III, Class 1, Components</u>

The PBNP Reactor Pressure Vessels, CRDMs, Steam Generators, and Pressurizers were designed, constructed, and analyzed to the requirements of their original Equipment Specifications, and Section III of the ASME Code. The PBNP Reactor Vessels Internals, and Reactor Coolant Pumps were designed, constructed, and analyzed to the requirements of their original Equipment Specifications, and the intent of Section III of the ASME Code.

The fatigue calculations were reanalyzed for the above noted Components at full uprated conditions using the revised transient set for a 60-year operating period. The structural evaluations concluded that all components analyzed for fatigue are within the allowable limits for a 60-year operating period, with the exception of the Unit 1 Steam Generator inspection port bolts. The structural evaluation identifies a replacement interval of 12 years for the inspection port bolts.

In addition to the original ASME CLB analysis, a PBNP plant specific insurge/outsurge fatigue analysis was performed for the extended license period. The analysis demonstrated acceptable structural integrity for the affected pressurizer locations to the end of license extension.

With the sole exception of the Unit 1 steam generator inspection port bolting, the analyses associated with verifying the structural integrity of the PBNP ASME III Class 1 components have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

The Periodic Surveillance and Preventative Maintenance Program will provide reasonable assurance that the Unit 1 SG inspection port bolt replacement is adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

<u>Pressurizer Surge Line Structural Integrity</u>

Detailed fatigue analyses of the pressurizer surge lines were performed in response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification.” The analyses were performed in accordance with the requirements of Section III of the ASME Code. The methodology and results are presented in WCAP-13509, “Structural Evaluation of the

Point Beach Units 1 & 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification."

Subsequently, the PBNP specific surge line fatigue analysis was re-evaluated considering the operational conditions associated with power uprate and a 60-year operating period. The transient sets were reviewed for the new conditions. The majority of the transients defined for original power levels for 40 years were found to be bounding for uprated conditions for 60 years. Some of the feedwater transients required minor revision due to a change in feedwater temperatures associated with the proposed power uprate. The impact of the changes in the revised RCS conditions, thermal design transients, and the 60-year life were factored into determining the ASME stress levels and allowables for the surge line.

The results of the evaluation for the pressurizer surge line stratification showed that the power uprate conditions changed the fatigue usage factors at the location of the highest usage factor by a negligible amount. The calculated change in the loadings on the pressurizer nozzle due to stratification for the power uprate conditions was not considered significant. The results of the original evaluation for the surge line, WCAP-13509, remain unchanged for the 60-year operating period.

The analysis associated with verifying the structural integrity of the pressurizer surge line piping has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Spray Header Piping Structural Integrity

Piping connections to the RCS were evaluated in response to NRC IB 88-08 (including supplements 1 through 3) "Thermal Stresses in Piping Connected to Reactor Coolant Systems." Two un-isolable piping connections were identified that had the potential to be subjected to thermal stratification or temperature oscillations. These lines are the auxiliary charging connection, and auxiliary spray connection. These lines were subject to temperature monitoring to identify and quantify thermal stratification. No thermal stratification was noted on the auxiliary charging lines. Thermal stratification was noted on one of the auxiliary spray lines, where it ties into the spray header.

To evaluate the effect of thermal stratification on the pressurizer spray line header, including the auxiliary spray line connection, fatigue analyses were performed for each unit's applicable piping system. The analyses were based on actual piping surface temperature data obtained during a 153-day period (including one startup) of direct temperature monitoring on the Unit 2 piping. The Unit 2 data was considered applicable and bounding for both units since it experienced more stratification, and the line configuration was similar. The piping transient set was developed by expanding the measured piping thermal behavior to equate to a 60-year operating period. The analyses showed that the CUFs in the subject piping were acceptable.

The analysis associated with verifying the structural integrity of the pressurizer auxiliary spray line, and spray header, have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

USAS B31.1 Piping Structural Integrity

In general, piping and associated pressure boundary components at PBNP were originally designed to the requirements of USAS B31.1, USA Standard Code for Pressure Piping. The B31.1 Code requirements assume a stress range reduction factor to provide conservatism in the piping design to account for the effects of thermal fatigue due to thermal cycling during operation. This reduction factor is 1.0 provided that the number of anticipated cycles is limited to 7000 equivalent full temperature cycles. This represents a condition where a piping system would have to be cycled approximately once every 3 days over the extended plant life of 60 years. Considering this limit, a review of the piping and associated pressure boundary components was performed to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Under current plant operating practices, piping is generally only occasionally subject to cyclic operation. Typically, piping is subject to continuous steady-state operation and operating temperatures only vary during plant heatup and cooldown, during plant transients, or during periodic testing. It is therefore very unlikely, for any piping system subject to thermal fatigue, that the actual number of thermal cycles would approach the assumed B31.1 limit of 7000 during the period of extended operation except for the Primary Sampling System lines. Establishing sample flow from the RCS results in thermal transients and cyclic stresses whenever the RCS is above ambient temperatures. The hot leg sample line receives the highest number of thermal cycles of all PBNP piping. An evaluation of the number of thermal cycles that the hot leg sample line would be expected to experience over a 60-year period of operation was performed in PBNP License Renewal Technical Report, LR-TR-516. The Technical Report demonstrates that the PBNP hot leg sample line will not exceed 7000 thermal cycles over a 60-year operating period. Thus, no PBNP piping is expected to exceed 7000 thermal cycles over a 60-year operating period, and thus remain within the bounds of their original design code.

The analyses associated with USAS B31.1 piping fatigue have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(C)(1)(i).

Environmental Effects on Fatigue

As a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term, Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260 (Reference 10), fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system vendors. The pressurized water reactor calculations, especially the early-vintage Westinghouse calculations, are directly relevant to PBNP. In addition, the transient cycles considered in the evaluation match or bound the PBNP design.

The fatigue-sensitive component locations chosen in NUREG/CR-6260 for the early-vintage Westinghouse plant were:

1) The reactor vessel shell and lower head

2) The reactor vessel inlet and outlet nozzles

3) The pressurizer surge line (including the pressurizer and hot leg nozzles)

4) The Reactor Coolant System piping charging system nozzle

5) The Reactor Coolant System piping safety injection nozzle

6) The Residual Heat Removal System Class 1 piping

In addition to the NUREG/CR-6260 locations, the PBNP pressurizers were evaluated for the effects of coolant environment on fatigue, including insurge / outsurge transients, in accordance with Applicant Action Item 3.3.1.1-1 of the pressurizer Generic Technical Report WCAP-14574-A.

Environmental fatigue evaluations were performed for the NUREG/CR-6260 component locations, and the pressurizers using the F_{en} methodology contained in NUREG/CR-6583 for carbon/low alloy steel material, and NUREG/CR-5704 for stainless steel material.

The effects of reactor coolant environment on component fatigue life during the period of extended operation have been evaluated at PBNP. The evaluation includes the seven component locations identified in NUREG/CR-6260, and the Pressurizer. Appropriate environmental fatigue factors have been applied to either the components design cumulative fatigue usage factor, or the components forecasted cumulative fatigue usage factor, based on actual operational transient monitoring by the EPRI FatiguePro software. The evaluations result in acceptable environmentally adjusted cumulative fatigue usage factors at EOLE for all of the component locations considered.

The Fatigue Monitoring Program is a confirmatory program that monitors loading cycles due to thermal and pressure transients for selected critical components. The program provides an analytical basis for confirming that the number of cycles established by the analysis of record will not be exceeded before the end of the period of extended operation

Containment Liner Plate and Penetrations Fatigue Analysis

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. The fatigue loads as described in FSAR, Section 5.1, were considered in the design of the liner plates and are considered time-limited aging analyses for the purposes of license renewal. Each of these has been evaluated for the period of extended operation.

The number of thermal cycles due to annual outdoor temperature variations was increased from 40 to 60 for the extended period of operation. 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 Reactor Coolant System. The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 Reactor Coolant System 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 period of extended operation as it is enveloped by the evaluation for 500 thermal cycles.

The assumed 500 thermal cycles was evaluated based on the more limiting 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 determined that the originally projected number of maximum Reactor Coolant System design cycles is conservative enough to envelop the projected cycles for the extended period of operation. Therefore, the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is considered valid for the period of extended operation.

The assumed value of one 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 period of extended operation.

The design of the containment penetrations has been reviewed. 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 60 years of operation was determined to be less than the original design limits.

The analyses associated with the containment liner plate and penetrations have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Crane Load Cycle Limit

The Containment Polar Cranes, Auxiliary Building Crane, and Turbine Hall Crane are included within the scope of license renewal and NUREG-0612.

The load cycle limit for PBNP cranes was identified as a time-limiting-aging analysis.

All PBNP cranes were designed and constructed to meet the requirements of Specification 61 of the Electric Overhead Crane Institute (EOCI-61).

NUREG-0612 required that the design of heavy load overhead handling systems meet the intent of Crane Manufactures Association of America, Inc. (CMAA) Specification No. 70. Per guideline 7, NUREG-0612, Section 5.1.1(7), the design of the PBNP cranes listed above was evaluated in relation to the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, “Overhead and Gantry Cranes,” and of CMAA-70, “Specifications for Electric Overhead Traveling Cranes.” The PBNP cranes listed above substantially meet the criteria of CMAA-70 “Specifications for Electric Overhead Traveling Cranes,” as noted in the NRC NUREG-0612 safety evaluation. Cranes designed in accordance with CMAA-70 Class “A” service are designed for 20,000 to 200,000 load cycles.

The PBNP containment polar cranes and the turbine hall crane are used primarily during refueling outages. The PBNP auxiliary building crane is primarily used in support of material receipt (fuel and consumables), spent fuel cask transfers, and radwaste cask transfers. Occasionally, these cranes make lifts at or near their rated capacity. However, the majority of the crane lifts are substantially less than their rated capacity. Based on conservative usage assumptions, the above listed PBNP cranes are expected to make 50,000 partial load lifts over a 60-year operating period. This is significantly less than the CMAA-70 design cycle limit for Class “A” service cranes.

The specifications for the noted travelling cranes at PBNP included rated overload cycle limits of roughly two 125 percent rated load lifts per year, and three 150 percent rated load lifts in the cranes lifetime. With the exception of the containment polar cranes, no lifts in excess of the rated load have been made. Each containment polar crane was used to support its respective units steam generator replacement project. These lifts incorporating the containment polar cranes were specifically analyzed engineered lifts incorporating temporary replacement trolleys, bridge strengthening, and temporary center poles to ensure that the original design capabilities of the cranes were not degraded. Thus, since the major cranes are not used to make routine over rated load lifts, and special one-time over rated load maintenance lifts are addressed as specific engineered lifts, the original specified cycle limits for over rated load lifts will not be exceeded during the extended operating period.

Since the number of operating load cycles for the cranes will be fewer than the design cycles, the crane design will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

15.4.3 Fracture Mechanics Analysis

Reactor Coolant Pump Flywheel Analysis

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 that 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 extended period of operation was performed in WCAP-14535-A for all operating Westinghouse plants and certain Babcock and Wilcox plants. It demonstrates 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 NRC reviewed and approved the evaluation (WCAP-14535-A) for application with certain conditions and limitations (Reference 2). PBNP verified the RCP flywheel material and invoked this analysis as the basis for reducing the frequency of performing RCP flywheel inspections (Reference 3).

The analysis associated with the structural integrity of the reactor coolant pump flywheel has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Reactor Coolant Pump Casing Analysis (ASME Code Case N-481 Analysis)

The ASME Section XI Code, up to and including the 1998 edition, required a volumetric inspection of the RCP casing welds, and a visual inspection of the pressure boundary components. In lieu of performing the required Section XI internal visual and volumetric inspections of RCP CASS casings, a fracture mechanics analysis, supplemented by visual examinations, per the requirements of ASME Code, Case N-481 was performed for the original operating period of 40 years. This analysis is contained in the generic industry WCAP-13045, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems,” and the PBNP specific WCAP-14705, “A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Point Beach Units 1 and 2.” These analyses incorporated the effects of thermal embrittlement, and demonstrated compliance with Code Case N-481 requirements for the original 40-year operating license period.

The current ASME Section XI Code applicable for PBNP does not require pump casing weld volumetric, or routine internal visual examinations. Thus, the fracture mechanics analysis is not necessary for the extended period of operation in support of applying Code Case N-481 to eliminate casing volumetric examinations. However, the GTR for Class 1 Piping and Associated Pressure Boundary Components, WCAP-14575-A, “License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components,” identifies that a fracture mechanics analysis performed for the extended operating period is an acceptable means of managing thermal aging of CASS. Thus, the Code Case N-481 integrity analysis was evaluated throughout the extended period of operation.

Westinghouse performed an evaluation of the Code Case N-481 integrity analysis to identify if it is acceptable for the extended operating period. The results of the evaluation show that the ASME Code Case N-481 integrity analysis conclusions, documented in WCAP-13045 and WCAP-14705 for the PBNP Units 1 and 2 RCP casings remain valid for the 60-year licensed operating period.

The Reactor Coolant Pump Integrity Analysis has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis

In response to Unresolved Safety Issue (USI) “A-2” (Asymmetric Blowdown Loads on the Reactor Coolant System), Westinghouse performed a generic Leak-Before-Break (LBB) analysis, which was applicable to PBNP. 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 and approved the generic Westinghouse LBB evaluation in NRC Generic Letter 84-04, “Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Main Loops.” By letter (Reference 4) dated May 6, 1986, the NRC acknowledged that PBNP was bounded by the generic Westinghouse LBB analysis and met the additional criteria identified in NRC Generic Letter 84-04.

A plant specific LBB analysis for the PBNP Units 1 and 2 primary coolant loop piping was subsequently performed by Westinghouse in 1996, and revised in 2002 and 2003. The results of the current PBNP LBB analysis are documented in WCAP-14439, Revision 2, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 for the Power Uprate and

License Renewal Program." The report demonstrates compliance with LBB technology for the PBNP RCS piping based on plant specific analysis, using the methodology and criteria of Standard Review Plan Section 3.6.3. The revised LBB analysis incorporates analysis parameters associated with power uprate conditions, and a 60-year operating period. This revision documents the plant specific reactor coolant system main loop piping geometry, loading, and material properties used in the fracture mechanics evaluation. Since the primary loop piping systems include cast stainless steel fittings, end of life (60-year) fracture toughness, considering the effects of thermal aging, was determined for each heat of material.

Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 60 years was shown to be acceptable for the primary loop piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

Pressurizer Surge Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 pressurizer surge line piping was performed in 1998. The results of the analysis are documented in WCAP-15065. The report demonstrates compliance with LBB technology for the PBNP pressurizer surge line piping based on plant specific analysis. Westinghouse revised WCAP-15065 to include the NRC SER approving the LBB analysis for the PBNP Units 1 and 2 pressurizer surge line piping in 2001. This revision is documented in WCAP-15065-P-A, Revision 1, "Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for the Point Beach Units 1 and 2 Nuclear Plants." The pressurizer surge line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. The LBB analysis includes the effects of thermal stratification, as evaluated for the PBNP surge lines in WCAP-13509, "Structural Evaluation of the Point Beach Units 1 and 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification." WCAP-15065-P-A documents the plant specific pressurizer surge line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the pressurizer surge line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the pressurizer surge line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The pressurizer surge line LBB analysis was further evaluated to determine the impacts of uprated power conditions, and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast pipe fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15065-P-A, remained unchanged.

The pressurizer surge line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Class 1 Accumulator Injection Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 accumulator injection line piping was performed in 1998. The scope of the analysis for the accumulator injection lines also includes the residual heat removal (RHR) return line. The results of the analysis are documented in WCAP-15107. The report demonstrates compliance with LBB technology for the PBNP accumulator injection line piping based on plant specific analysis. Westinghouse revised WCAP-15107 to include the NRC SER approving the LBB analysis for the PBNP Units 1 and 2 accumulator injection line piping in 2001. This revision is documented in WCAP-15107-P-A, Revision 1, “Technical Justification for Eliminating Accumulator Lines Rupture as the Structural Design Basis for the Point Beach Units 1 and 2 Nuclear Plants.” The accumulator injection line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. WCAP-15107-P-A documents the plant specific accumulator injection line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the accumulator injection line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the accumulator injection line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The accumulator injection line LBB analysis was further evaluated to determine the impacts of uprated power conditions, and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15107-P-A, remained unchanged.

The accumulator injection line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

<u>Class 1 RHR Line Piping Leak-Before-Break Analysis</u>

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 residual heat removal (RHR) suction line piping was performed in 1998. The results of the analysis are documented in WCAP-15105. The report demonstrates compliance with LBB technology for the PBNP RHR line piping based on plant specific analysis. Westinghouse revised WCAP-15105 to include the NRC SER approving the LBB analysis for the PBNP Units 1 and 2 RHR line piping in 2001. This revision is documented in WCAP-15105-P-A, Revision 1, “Technical Justification for Eliminating Residual Heat removal (RHR) Lines Rupture as the Structural Design Basis for the Point Beach Units 1 and 2 Nuclear Plants.” The RHR line LBB analysis includes the effects of thermal stratification. The RHR line

LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. WCAP-15105-P-A documents the plant specific RHR line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the RHR line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in the draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the RHR line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied. The RHR line LBB analysis was further evaluated to determine the impacts of uprated power conditions, and a 60-year operating period.

The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15105-P-A, remained unchanged.

The RHR line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

15.4.4 Loss of Preload

Containment Tendon Loss of Prestress Analysis

The PBNP Units 1 and 2 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 and dome are provided with tendons.

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. New upper limit curves, and lower limit curves, of prestressing forces have been established for all tendons through the period of extended operation. The predicted final effective preload at the end of 60 years exceeds the minimum required preload for all containment tendons. Consequently, the post-tensioning system will continue to perform its intended function throughout the period of extended operation.

The analyses associated with containment tendon loss of prestress have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

As a confirmatory measure, the Pre-Stressed Concrete Containment Tendon Surveillance Program monitors the loss of prestressing forces in the containment tendons. This program consists of an assessment of the results of the tendon prestressing force measurements performed in accordance with ASME Section XI, Subsection IWL.

15.4.5 **Neutron Absorber**

<u>Spent Fuel Pool Storage Rack Boraflex</u>

The PBNP spent fuel storage racks contain boraflex sheets installed between adjacent cells of the storage racks. The Boraflex is used as a neutron absorber to allow close spacing of the fuel assemblies. The Boraflex is sandwiched between stainless steel plates. Openings on the top of the panels allow venting of gases, but do not allow a significant flow path around the Boraflex material.

The Spent Fuel Pool criticality analysis credits the presence of Boraflex material located between the adjacent storage cells within the spent fuel racks. Although the analysis is not based on time assumptions, the criticality analysis allows for a limited reduction in the concentration of the neutron absorbing material located between the adjacent storage cells. Boraflex degradation studies have been based on the integrated dose expected during service for 40 years. Thus, this issue is considered a TLAA for PBNP.

Boraflex is boron carbide dispersed in an elastomeric silicone. When Boraflex is subjected to gamma radiation, shrinkage and the potential to develop tears or gaps in the material can occur. The radiation exposure alters the chemical properties of the polymer matrix by weakening the chemical bonds. As a result of being in a convective aqueous environment in the spent fuel pool (SFP), the silicon polymer matrix becomes degraded and silica filler and boron carbide are released.

Site surveillance testing of irradiated Boraflex panels revealed significant decreases in Boraflex thickness, width, height, weight, and that the Boraflex sheets were fragile and easily broken. Boraflex degradation was identified by the NRC in Generic Letter 96-04, “Boraflex Degradation in Spent Fuel Pool Storage Racks,” as a potential age-related condition and is listed as a Generic Safety Issue in GSI 173.A, “Spent Fuel Storage Pool: Operating Facilities.” The degradation was due to gamma radiation-induced shrinkage and silica dissolution from the Boraflex panels.

The Boraflex Monitoring Program manages aging effects for the Boraflex material in the spent fuel racks. This program provides for blackness testing and areal density measurements of the Boraflex material in the spent fuel storage racks to confirm the in-service Boraflex performance. In addition, tracking of the spent fuel pool silica levels provides a qualitative indication of boron carbide loss. Neutron attenuation or blackness testing will be performed to determine gap formation, while areal density measurements will be used to ascertain the physical loss of boron carbide. Monitoring and analysis of criticality will also be performed to assure that the required 5% subcriticality margin is maintained. Based on the results of these inspections and analysis, appropriate measures will be taken to ensure the Boraflex will continue to perform its intended function. This program addresses the concerns described in NRC GL 96-04.

The Boraflex Monitoring Program for the Boraflex panels will provide reasonable assurance that the equipment will be adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

15.4.6 Environmental Qualification

Environmental Qualification of Electrical Equipment

The Nuclear Regulatory Commission (NRC) has established nuclear plant EQ requirements in 10 CFR 50, Appendix A, Criterion 4, “Environmental and Dynamic Effects Design Bases,” and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments (that is, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation) are qualified to perform their safety function in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

The EQ Program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected. 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) also requires replacement or refurbishment of components qualified for less than 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.

The license renewal rule, 10 CFR 54, requires that for each structure and component subject to an Aging Management Review (AMR), the licensee shall demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. The EQ Program 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. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered time-limited aging analyses (TLAA) for license renewal. The PBNP EQ Program ensures that these EQ components are maintained within the bounds of their qualification bases.

EQ equipment is identified and tabulated in the Master List of Electrical Equipment to be Environmentally Qualified (EQML). This list references the Equipment Qualification Summary Sheets (EQSS), which contain pertinent information that establishes qualified life and applicable environmental parameters.

The EQ Program has been demonstrated to be capable of programmatically managing the qualified lives of the components falling within the scope of the program for license renewal. Based upon a review of the existing program and operating experience, the effective implementation of the EQ Program will provide reasonable assurance that (a) the aging effects will be managed, and (b) EQ components will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation.

Therefore, the EQ Program will be an acceptable aging management program for license renewal under 10 CFR 54.21(c)(1)(iii) during the period of extended operation.

15.5 EXEMPTIONS

The requirements of 10 CFR 54.21(c) stipulate that the application for a renewed license should include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and that are based on time-limited aging analyses, as defined in 10 CFR 54.3. Each active 10 CFR 50.12 exemption has been reviewed to determine whether the exemption is based on a time-limited aging analysis. No existing TLAA related exemptions were identified.

A tabular summary of the proposed Master Curve related exemptions and the alternatives are shown in Table 15.5-1 below.

Table 15.5-1 Active Exemptions Associated with Time-Limited Aging Analyses

Exemption Description	Existing Requirement	Alternative Used	Date Granted / Associated TLAA
Exemptions Applicable to Master Curve			
Determination of adjusted/indexing reference temperatures	10 CFR 50.61 and Appendix G to 10 CFR 50	ASME Code Case N-629, ASME Code Case N-631, ATI Consulting Report 021-030-2003-1, BAW-2308, Revision 1, and Framatome ANP Calculation 32-5019743-01.	Submitted / Pressurized Thermal Shock
Use of the latest edition of supplemental ASTM E185-98	App H to 10 CFR 50 specifies use of ASTM E185-73, -79, -82 for testing of surveillance materials	(1) ASTM E185-98 allows use of ASTM E1921-02 for testing of surveillance capsule material; (2) Use fracture toughness surveillance data from PBNP Unit 2 surveillance capsule for verification of EOLE toughness properties. Capsule withdrawal will be managed by the Reactor Vessel Surveillance Program.	Submitted / Pressurized Thermal Shock
Alternative testing methods for determination of fracture toughness	Appendices G and H to 10 CFR 50 specifies Charpy V-Notch impact and drop weight testing	ASTM E1921-02, ATI Consulting Report and 021-030-2003-1.	Submitted / Pressurized Thermal Shock

15.0 REFERENCES

1. ATI Consulting Report, ATI-021-030-2003-1, “Master Curve Fracture Toughness Application for Point Beach Nuclear Plant Unit 2”, January 2003.

2. NRC Letter, “Acceptance for referencing of Topical Report WCAP-14535-A, “Topical report on Reactor Coolant Pump Flywheel Inspection Elimination,” To: Sushil C. Jain, Division Vice President, From: Brian W. Sheron, Director, Dated September 12, 1996.

3. NMC Letter, NRC 2001-059, “Reactor Coolant Pump Flywheel Inspection Interval Change Point Beach Nuclear Plant, Units 1 and 2,” To; Nuclear Regulatory Commission, From: Thomas J. Webb, Licensing Director, dated September 17, 2001.

4. NRC Letter, “Docket Nos. 50-266 and 50-301,” To: C. W. Fay, Vice President, From: G. E. Lear, Director - PWR Project Directorate #1, dated May 6, 1986.

5. EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” dated April 1988.

6. EPRI TR-104213, “Bolted Joint Maintenance & Applications Guide,” dated December 1995.

7. EPRI Nuclear Safety Analysis Center NSAC 202L, “Recommendations for an Effective Flow Accelerated Corrosion Program,” Revision 2, dated 4/8/99.

8. TR-105714, “EPRI PWR Primary Water Chemistry Guidelines” (Revision 4, dated March 1999)

9. TR-102134, “EPRI PWR Secondary Water Chemistry Guidelines” (Revision 5, dated March 2000)

10. NUREG/CR-6260 (INEL-95/0045), “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,” U. S. Nuclear Regulatory Commission, March 1995.

APPENDIX B

AGING MANAGEMENT PROGRAMS

APPENDIX B
Contents

B1.0 APPENDIX B INTRODUCTION

B1.1 Overview

Aging management program descriptions are provided in this appendix for each program credited for managing aging effects based upon the aging management review results provided in Sections 3.1 through 3.6.

Each of the aging management programs presented in this section has been evaluated for the ten elements described in Appendix A.1, "Aging Management Review - Generic," Table A.1-1, "Elements of an Aging Management Program for License Renewal," of NUREG-1800, SRP-LR (Reference 1). Details of the evaluation of each of the 10 elements is provided for each program that is deemed to be consistent with or consistent with exceptions to the assumptions made in NUREG-1801, as well as for the plant-specific programs. These aging management programs are described as if the identified enhancements to the programs have been implemented. Enhancements to the aging management programs are also described in this appendix. See Section B1.2 below.

B1.2 Method of Discussion

For those aging management programs that are consistent with or consistent with exceptions to the assumptions made in Sections X and XI of NUREG-1801 each program discussion is presented in the following form.

- A Program Description abstract of the over all program form and function is provided.
- A NUREG-1801 Consistency statement is made about the program.
- Exceptions to the NUREG-1801 program are outlined and a justification provided. Exceptions are areas where the program does not implement recommendations in the NURG-1801 program elements. Exceptions may also include different ways of implementing recommendations outlined in NUREG-1801.
- Enhancements to the program are identified. These enhancements include those needed to ensure consistency with NUREG-1801 or provide additional features to the program (e.g., manage aging for additional components or aging effects not assumed in NUREG-1801). A proposed schedule for completion is also discussed.
- An element by element discussion is provided for each program. Comparisons are made to and consistency evaluated for each NUREG-1801 program element.
- A Conclusion section that provides reasonable assurance that the program is or will be effective once enhanced.

For those aging management programs that are plant-specific each program discussion is presented in the following form.

- A Program Description abstract of the over all program form and function is provided.
- Enhancements to the program to ensure consistency with the NUREG-1800 Branch Technical Position program elements are identified. A proposed schedule for completion is also discussed.
- An element by element discussion is provided for each program.
- A Conclusion section that provides reasonable assurance that the program is or will be effective once enhanced.

B1.3 Quality Assurance Program and Administrative Controls

The PBNP Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2 of NUREG-1800 (Reference 1). The elements of corrective action, confirmation process, and administrative controls in the Quality Assurance Program will be applicable to both safety related and non-safety related systems, structures, and components that are subject to an aging management review. Generically, these three elements will be applicable as follows:

Corrective Actions and Confirmation Process:

A single corrective actions process is applied at PBNP, regardless of the safety classification of the structure or component. Corrective actions are implemented through the initiation of an Action Request (AR) in accordance with plant procedures established in response to 10 CFR 50, Appendix B. Plant procedures require the initiation of an AR for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction or loss.

Equipment deficiencies are corrected through the initiation of a Work Order (WO) in accordance with plant procedures. Although equipment deficiencies may initially be documented by a WO, the corrective action process specifies that an AR also be initiated as discussed above.

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 the adverse condition and precluding repetition of significant conditions adverse to quality. Plant procedures include provisions for timely evaluation of adverse conditions and implementation of any corrective actions required, including root cause determinations and prevention of recurrence where appropriate (e.g., significant conditions adverse to quality). These procedures provide for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The AR process is also monitored for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions would result in the initiation of an AR. The aging management activities required for license renewal would also uncover any unsatisfactory condition due to ineffective corrective action.

Since the same 10 CFR 50, Appendix B corrective actions and confirmation process is applied for nonconforming SR and NSR structures and components subject to an AMR for license renewal, we have concluded that the PBNP corrective action program is currently consistent with these NUREG-1801 and NUREG-1800 elements.

Site documents that implement aging management activities for license renewal will be enhanced to ensure that an AR is prepared in accordance with plant procedures whenever non-conforming conditions are found (i.e., the acceptance criteria is not met).

Administrative Controls:

The administrative controls for license renewal related procedures and other document types are consistent with NUREG-1801 and NUREG-1800 for this element where plant procedural controls are invoked either directly or through intermediary control procedures. The following conclusions can be drawn for each document type:

- Technical and administrative procedures have administrative controls that are consistent with this NUREG-1801 and NUREG-1800 element.
- Maintenance procedures and instructions are subject to administrative controls that are consistent with this NUREG-1801 and NUREG-1800 element.
- Controlled Reference Documents have administrative controls that are consistent with this NUREG-1801 and NUREG-1800 element.
- Design Guidelines are subject to administrative controls that are consistent with this NUREG-1801 and NUREG-1800 element.
- Call-ups (i.e., scheduled work documents) are subject to administrative controls that are consistent with this NUREG-1801 and NUREG-1800 element.
- PBNP forms are subject to administrative controls that are consistent with this NUREG-1801 and NUREG-1800 element.
- QA-scope calculations are subject to administrative controls that are consistent with this NUREG-1801 and NUREG-1800 element.

Enhancements to license renewal related procedures and other document types will be made to include a purpose section discussing management of the effects of aging for systems, structures and components within the scope of license renewal with applicable references.

B1.4 Operating Experience

Industry operating experience was incorporated into the License Renewal process through a review of industry documents to identify aging effects and mechanisms that could challenge the intended function of structures and components within the scope of License Renewal. Review of plant-specific operating experience was performed to identify aging effects experienced. The review of plant-specific operating experience involved electronic database searches of information from PBNP. The database searches were of historical data. In addition, discussions with system engineers and long time company employees were conducted to identify any additional aging concerns. See Section 3.0.1.7.

The programs identified for aging management are discussed in this appendix. Operating experience of the program/activity, including past corrective actions resulting in program enhancements, were also considered. This information provides objective evidence that the effects of aging have and will continue to be adequately managed.

B1.5 Aging Management Programs

The following aging management programs are described in the sections listed in this appendix. The programs are either generic in nature as discussed in NUREG-1801 or are plant-specific. Plant-specific programs are listed near the end of the table in Section B2.0. Generic programs are either fully consistent with or are, with some exceptions, consistent with the programs discussed in NUREG-1801.

1. ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program [Section B2.1.1] [Existing]
2. ASME Section XI, Subsections IWE & IWL Inservice Inspection Program [Section B2.1.2] [Existing]
3. ASME Section XI, Subsection IWF Inservice Inspection Program [Section B2.1.3] [Existing]
4. Bolting Integrity Program [Section B2.1.4] [Existing]
5. Boraflex Monitoring Program [Section B2.1.5] [Existing]
6. Boric Acid Corrosion Program [Section B2.1.6] [Existing]
7. Buried Services Monitoring Program [Section B2.1.7] [New]
8. Cable Condition Monitoring Program [Section B2.1.8] [New]
9. Closed-Cycle Cooling Water System Surveillance Program [Section B2.1.9] [Existing]

10. Fire Protection Program [Section B2.1.10] [Existing]
11. Flow-Accelerated Corrosion Program [Section B2.1.11] [Existing]
12. Fuel Oil Chemistry Control Program [Section B2.1.12] [Existing]
13. One-Time Inspection Program [Section B2.1.13] [New]
14. Open-Cycle Cooling (Service) Water System Surveillance Program [Section B2.1.14] [Existing]
15. Periodic Surveillance and Preventive Maintenance Program [Section B2.1.15] [Existing]
16. Reactor Coolant System Alloy 600 Inspection Program [Section B2.1.16] [New]
17. Reactor Vessel Internals Program [Section B2.1.17] [Existing]
18. Reactor Vessel Surveillance Program [Section B2.1.18] [Existing]
19. Steam Generator Integrity Program [Section B2.1.19] [Existing]
20. Structures Monitoring Program [Section B2.1.20] [Existing]
21. Systems Monitoring Program [Section B2.1.21] [Existing]
22. Tank Internal Inspection Program [Section B2.1.22] [New]
23. Thimble Tube Inspection Program [Section B2.1.23] [Existing]
24. Water Chemistry Control Program [Section B2.1.24] [Existing]

B1.6 Time Limited Aging Analyses Aging Management Programs:

1. Environmental Qualification Program [Section B3.1] [Existing]
2. Fatigue Monitoring Program [Section B3.2] [Existing]
3. Pre-Stressed Concrete Containment Tendon Surveillance Program [Section B3.3][Existing]

B2.0 AGING MANAGEMENT PROGRAMS CORRELATION

Correlation between NUREG-1801 (Generic Aging Lessons Learned (GALL)) programs and PBNP programs are shown below. For the PBNP Programs, links to appropriate sections of this appendix are provided.

NUREG -1801 ID	NUREG-1801 Program	PBNP Program	NUREG -1801 Comparison
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, & IWD	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program [Section B2.1.1]	Consistent with Exceptions and Meets the Intent
XI.M2	Water Chemistry	Water Chemistry Control Program [Section B2.1.24]	Consistent with Exceptions and Meets the Intent
XI.M3	Reactor Head Closure Studs	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program [Section B2.1.1]	Consistent with Exceptions and Meets the Intent
XI.M4	BWR Vessel ID Attachment Welds	Not Applicable, PBNP is a PWR.	N/A
XI.M5	BWR Feedwater Nozzle	Not Applicable, PBNP is a PWR.	N/A
XI.M6	BWR Control Rod Drive Return Line Nozzle	Not Applicable, PBNP is a PWR.	N/A
XI.M7	BWR Stress Corrosion Cracking	Not Applicable, PBNP is a PWR.	N/A
XI.M8	BWR Penetrations	Not Applicable, PBNP is a PWR.	N/A
XI.M9	BWR Vessel Internals	Not Applicable, PBNP is a PWR.	N/A
XI.M10	Boric Acid Corrosion	Boric Acid Corrosion Program [Section B2.1.6]	Consistent
XI.M11	Nickel-Alloy Nozzles and Penetrations	Reactor Coolant System Alloy 600 Inspection Program [Section B2.1.16]	Consistent with Exceptions and Meets the Intent

NUREG -1801 ID	NUREG-1801 Program	PBNP Program	NUREG -1801 Comparison
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Not Applicable - not credited for aging management. Degradation sustained from the effects of thermal embrittlement was determined to be significant for CASS Class 1 piping and associated pressure boundary components, which encompasses CASS RCS elbows, RCP casings, and CASS Class 1 valves exceeding a temperature threshold criteria of 482 degrees F. PBNP has chosen the evaluation method (fracture mechanics) to disposition reduction in fracture toughness due to thermal embrittlement of primary loop elbows and RCP casings. In addition, the CASS RCP casings have been determined to not be susceptible to thermal aging embrittlement. PBNP has no large CASS valves (>10") above 482 degrees F. Standard valve body design practices cause valve bodies to be inherently tough. Thus, an aging management program to manage thermal embrittlement for the CASS RCS elbows, RCP casings, and Class 1 CASS valves is not required beyond the examinations programmatically required by ASME Section XI.	N/A
XI.M13	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Reactor Vessel Internals Program [Section B2.1.17]	Consistent with Exceptions and Meets the Intent

NUREG -1801 ID	NUREG-1801 Program	PBNP Program	NUREG -1801 Comparison
XI.M14	Loose Part Monitoring	Not Applicable - not credited for aging management. Reactor Vessel Internals Program [Section B2.1.17] was determined to be adequate to manage identified aging effects.	N/A
XI.M15	Neutron Noise Monitoring	Not Applicable - not credited for aging management. Reactor Vessel Internals Program [Section B2.1.17] was determined to be adequate to manage identified aging effects.	N/A
XI.M16	PWR Vessel Internals	Reactor Vessel Internals Program [Section B2.1.17]	Consistent with Exceptions and Meets the Intent
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion Program [Section B2.1.11]	Consistent
XI.M18	Bolting Integrity	Bolting Integrity Program [Section B2.1.4]	Consistent with Exceptions and Meets the Intent
XI.M19	Steam Generator Tube Integrity	Steam Generator Integrity Program [Section B2.1.19]	Consistent and Plant Specific[a]
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling (Service) Water System Surveillance Program [Section B2.1.14]	Consistent with Exceptions and Meets the Intent
XI.M21	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System Surveillance Program [Section B2.1.9]	Consistent with Exceptions and Meets the Intent
XI.M22	Boraflex Monitoring	Boraflex Monitoring Program [Section B2.1.5]	Consistent with Exceptions and Meets the Intent
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Structures Monitoring Program [Section B2.1.20]	Consistent with Exceptions and Meets the Intent

NUREG -1801 ID	NUREG-1801 Program	PBNP Program	NUREG -1801 Comparison
XI.M24	Compressed Air Monitoring	Not applicable - not credited for aging management.	N/A
XI.M25	BWR Reactor Water Cleanup System	Not applicable, PBNP is a PWR.	N/A
XI.M26	Fire Protection	Fire Protection Program [Section B2.1.10]	Consistent with Exceptions and Meets the Intent[b]
XI.M27	Fire Water System	Fire Protection Program [Section B2.1.10]	Consistent with Exceptions and Meets the Intent[b]
XI.M28	Buried Piping and Tanks Surveillance	Not applicable - not credited for aging management.	N/A
XI.M29	Aboveground Carbon Steel Tanks	Systems Monitoring Program [Section B2.1.21]	Consistent with Exceptions and Meets the Intent and Plant Specific[c]
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry Control Program [Section B2.1.12]	Consistent with Exceptions and Meets the Intent
XI.M31	Reactor Vessel Surveillance	Reactor Vessel Surveillance Program [Section B2.1.18]	Consistent with Exceptions and Meets the Intent[d]
XI.M32	One-Time Inspection	One-Time Inspection Program [Section B2.1.13]	Consistent with Exceptions and Meets the Intent
XI.M33	Selective Leaching of Materials	One-Time Inspection Program [Section B2.1.13]	Consistent with Exceptions and Meets the Intent
XI.M34	Buried Piping and Tanks Inspection	Buried Services Monitoring Program [Section B2.1.7]	Consistent
XI.E1	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Cable Condition Monitoring Program [Section B2.1.8]	Consistent

NUREG -1801 ID	NUREG-1801 Program	PBNP Program	NUREG -1801 Comparison
XI.E2	Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Cable Condition Monitoring Program [Section B2.1.8]	Consistent with Exceptions and Meets the Intent
XI.E3	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Cable Condition Monitoring Program [Section B2.1.8]	Consistent with Exceptions and Meets the Intent
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program [Section B2.1.2]	Consistent with Exceptions and Meets the Intent
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program [Section B2.1.2]	Consistent with Exceptions and Meets the Intent
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF Inservice Inspection Program [Section B2.1.3]	Consistent with Exceptions and Meets the Intent
XI.S4	10 CFR 50, Appendix J	ASME Section XI, Subsections IWE & IWL Inservice Inspection Program [Section B2.1.2]	Consistent
XI.S5	Masonry Wall Program	Structures Monitoring Program [Section B2.1.20]	Consistent
XI.S6	Structures Monitoring Program	Structures Monitoring Program [Section B2.1.20]	Consistent
XI.S7	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Structures Monitoring Program [Section B2.1.20]	Consistent with Exceptions and Meets the Intent
XI.S8	Protective Coating Monitoring and Maintenance	Not Applicable - no credit is taken for protective coatings inside containment to prevent aging effects.	N/A

NUREG -1801 ID	NUREG-1801 Program	PBNP Program	NUREG -1801 Comparison
Chapter X			
X.M1	Metal Fatigue of Reactor Coolant Pressure Boundary	Fatigue Monitoring Program [Section B3.2]	Consistent
X.E1	Environmental Qualification (EQ) of Electrical Components	Environmental Qualification Program [Section B3.3]	Consistent
X.S1	Concrete Containment Tendon Prestress	Pre-Stressed Concrete Containment Tendon Surveillance Program [Section B3.1]	Consistent
Plant Specific			
NA	Plant-Specific Program	Thimble Tube Inspection Program [Section B2.1.23]	Plant Specific
NA	Plant-Specific Program	Tank Internal Inspection Program [Section B2.1.22]	Plant Specific
NA	Plant-Specific Program	Periodic Surveillance and Preventive Maintenance Program [Section B2.1.15]	Plant Specific

a.Plant specific aspects of the program deal with steam generator secondary side components not addressed by NUREG-1801, Section XI.M19.
b.The plant program was evaluated against the NUREG-1801 program as clarified by ISG-04.
c.The program includes visual inspections of the external surfaces of carbon steel tanks which are addressed by NUREG-1801, Section XI.M29.
d.NUREG-1801, Section XI.M31 does not list 10 separate elements that can be used in the evaluation. Therefore, this program was also evaluated against the Branch Technical Position RLSB-1 due to the non-standard format of NUREG-1801, Section XI.M31.

B2.1 Aging Management Programs Details

B2.1.1 ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

Program Description

ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (ISI) Program inspections are performed to identify and correct degradation in Class 1, 2, and 3 piping, components and their integral attachments. The program includes periodic visual, surface and/or volumetric examinations and leakage tests of all Class 1, 2 and 3 pressure-retaining components, and their integral attachments, including welds, pump casings, valve bodies, and pressure-retaining bolting. These components and their integral attachments are identified in ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” or commitments requiring augmented inservice inspections, and are within the scope of license renewal. This program is in accordance with 10 CFR 50.55a and approved Code Cases and Relief Requests.

The Code of Federal Regulations, 10 CFR 50.55a, requires that inservice inspection of Class 1, 2, and 3 pressure retaining components and their integral attachments be conducted in accordance with the latest edition of ASME Section XI approved by the NRC 12 months prior to the start of a ten-year interval. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program at PBNP is implemented by an Inservice Inspection (ISI) Program. The ISI Program for the fourth (4th) ten-year interval, which began on July 1, 2002 for both PBNP-1 and PBNP-2, will meet the 1998 edition through 2000 addenda (98A00) of ASME Section XI as modified by 10 CFR 50.55a and approved relief requests and code cases. Weld examinations for Class 1 and Class 2 piping will be performed in accordance with Risk-Informed Inservice Inspection (RI-ISI) selection and examination requirements. RI-ISI provides alternatives to ASME Section XI requirements based on the susceptibility to various degradation mechanisms and the consequences of component failure. The susceptibility assessment includes an evaluation for thermal and high cycle fatigue. RI-ISI will require examination of a sample of susceptible risk significant small bore (< 4 inch) Class 1 and 2 piping welds. RI-ISI will require volumetric examination of non-socket welds and surface examination of socket welds in the sample.

The ISI Program contains examination requirements for PBNP-1 and PBNP-2. Examination schedules are in accordance with Table IWB-2500-1 for Class 1 components, IWC-2500-2 for Class 2 components, and IWD-2500-1 for Class 3 components. RI-ISI alternative requirements apply to Categories B-J, B-F, C-F-1 and C-F-2. The program requires periodic visual, surface, and/or volumetric examinations and leakage tests of all Class 1, 2 and 3 pressure-retaining components and their integral attachments. The IWB-2500 Category B-Q requirements to perform volumetric examinations of steam generator tubes is addressed by the Steam Generator Integrity Program.

Class 1, 2 and 3 Pressure-Retaining Bolting

This program is credited by the Bolting Integrity Program for the inspection of Class 1, 2 and 3 pressure retaining bolting. Examination requirements are in accordance with ASME Section XI, Table IWB-2500-1 or IWC-2500-1. Nondestructive examination, repair and replacement of pressure retaining bolting are conducted as part of the ISI Program. When Class 1, 2 and 3 bolting must be replaced as a result of degradation, the Repair/Replacement Coordinator ensures that the preservice examination of the replacement bolting meets the ASME Section XI requirements for preservice examination.

Reactor Vessel Head Closure Studs

Nondestructive examination, repair and replacement of pressure retaining bolting are conducted as part of the ISI Program. Reactor vessel head closure studs are examined as required by Table IWB-2500-1, examination category B-G-1, “Pressure Retaining Bolting Greater than 2 inches in Diameter.” The reactor head closure studs are also visually examined during category B-P tests for all pressure-retaining components, which specifies visual VT-2 examination during the system leakage test. Volumetric examinations are performed using Performance Demonstration Initiative (PDI) techniques in accordance with ASME Section XI, Appendix VIII and 10 CFR 50.55a. Lubrication of the studs is controlled via maintenance procedures.

Relief Requests

The following Relief Requests (RR) have been approved by the NRC and have been incorporated into the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program:

- RR 1 - Altering the Date of the Start of the Fourth Inspection Interval

  SER 2001-0005 approved this Relief Request, which aligned the inspection intervals to be the same for PBNP-1 and -2. The fourth interval for both units began on July 1, 2002.

- RR 2 - Use of Later Code Editions

  SER 2001-0010 approved this Relief Request, which will allow the use of the 1998 Edition, 2000 Addenda of the ASME Section XI Code for both units during the fourth inspection interval.

- RR 3 - Risk Informed Examination of Class 1 and Class 2 Piping Butt Welds (Code Case N-578 and EPRI TR-112657)

  SER 2003-0009 approved this Relief Request, which will incorporate RI-ISI alternatives to Categories B-J, B-F, C-F-1, and C-F-2 ASME Section XI requirements based on an evaluation of the susceptibility to various degradation mechanisms and the consequences of component failure. It is being credited by this program for the examination of welds in small bore Class 1 and 2 piping.

- RR 4 - Alternate Requirements to Repair and Replacement Documentation Requirements and Inservice Inspection Summary Report Preparation and Submission as Required by IWA-4000 and IWA-6000 (Code Case N-532-1)

  SER 2003-0003 approved this Relief Request, which allows alternate reporting requirements that will not require the submittal of NIS-1 and NIS-2 forms for reporting the results of Inservice Inspection activities after each outage. This Relief Request has been superseded by Revision 13 of RG 1.147, “Inservice Inspection Code Case Acceptability ASME Section XI” (Reference 41).

- RR 5 - Alternate Requirements for VT-2 Visual Examination of Class 1, 2, and 3 Insulated Pressure-Retaining Bolted Connections. (Code Case N-533-1)

  SER 2002-0005 approved this Relief Request, which will allow VT-2 visual examination of Class 1, 2, and 3 bolted connections during system pressure tests to be performed without removing the insulation. The insulation will be removed from the bolted connections and a VT-2 visual examination performed each refueling outage for Class 1 connections and each period for Class 2 and 3 connections. The connections will not be required to be pressurized during the examination that occurs when the insulation is not in place. This Relief Request has been superseded by Revision 13 of RG 1.147.

- RR 6 - Corrective Action for Leakage Identified at Bolted Connections (Code Case N-566-1)

SER 2002-0006 approved this Relief Request, which allows a relaxation of the IWA-5250(a)(2) requirement to remove one of the bolts for visual examination and evaluation. As an alternative, an attempt will be made to stop the leakage and an evaluation of the susceptibility of the bolting to corrosion and failure will be performed. This Relief Request has been superseded by Revision 13 of RG 1.147.

- RR 7 - Alternate Requirements for VT-2 Visual Examination of Class 1, 2, and 3 Insulated Pressure-Retaining Bolted Connections, Section XI, Division 1 (Code Case N-616)

  SER 2003-0005 approved this Relief Request, which is applicable to Examination Categories B-G-1 and B-G-2. It allows a relaxation of the IWA-5242(a) requirement to remove insulation from pressure retaining bolted connections for the performance of VT-2 examinations, if the bolting is resistant to boric acid corrosion. Implementation of this Relief Request will allow VT-2 examinations during system pressure tests with the insulation left in place if the bolting material chromium content is greater than or equal to 10%. PBNP will inspect the insulation and areas under the bolted connection for evidence of leakage. A 4-hour hold time at operating temperature and pressure will be required prior to conducting the VT-2 examination. This Relief Request will also apply to SA-194 nuts. It does require insulation removal for 17-4PH stainless steel or 410 stainless steel studs or bolts aged at a temperature below 1100 degrees F or with hardness above R_C30, and for A-286 stainless steel studs or bolts with a preload $\geq$ 100Ksi. This Relief Request has been superseded by Revision 13 of RG 1.147.

- RR 8 - Successive Inspections (Code Case N-624)

  IWB-2420(a), IWC-2420(a), and IWD-2420(a) requires the sequence of component examinations that was established during the first inspection interval to be repeated during each successive inspection interval to the extent practical. SER 2003-0007 approved this Relief Request, which allows the sequence of examinations established in the previous inspection interval to be modified in a manner that reduces scaffold, insulation, and radiation exposure. The examinations will also be selected to coincide with the requirements of RI-ISI. This Relief Request has been superseded by Revision 13 of RG 1.147.

- RR 9 - Alternative to Welding and Brazing Performance Qualification Requirements

SER 2003-0004 approved this Relief Request, which allows the use of a welder, welding operator, brazer, or brazing operator qualified by other Owners as an alternative to the qualification requirements of IWA-4000.

- RR 10 - Relief from Regenerative Heat Exchanger Examinations

  SER 2003-0002 approved this Relief Request, which allows examination of only one of the three vessels comprising the Regenerative Heat Exchanger. The bottom vessel will be examined because it is the most severely stressed.

- RR 11 - Emergency Diesel System VT-2 Examination

  SER 2003-0006 approved this Relief Request, which allows the use of Technical Specification surveillance testing as an acceptable alternative to the system leakage test of Class 3 pressure retaining components. The auxiliary support systems addressed within the scope of this Relief Request include the starting air systems, fuel oil systems, and the G03 and G04 glycol cooling systems.

The following Relief Request has been submitted and is pending NRC approval:

- RR 12 Request for Alternative to ASME Section XI, Appendix VIII, Supplement 10.

  This Relief Request proposes the use of technical alternatives to certain qualification requirements for procedures, equipment, and personnel involved with the ultrasonic examination of dissimilar metal welds. The proposed technical alternatives were developed by the Performance Demonstration Initiative (PDI). This Relief Request, whether or not implemented, will not affect program inspection scope, schedule, acceptance criteria, or consistency with NUREG-1801.

Leak-Before-Break (LBB) Analyses

LBB analyses, including the period of extended operation and the effects of power uprate, were performed for the RCS main coolant loop, pressurizer surge line, and Class 1 portions of the accumulator injection and Residual Heat Removal (RHR) lines. New LBB analyses are performed if Class 1 welded connections or CASS components within the scope of the LBB analysis are repaired, replaced, or evaluated per IWA-4000 or IWB- 3600. The LBB analyses will account for thermal aging through the period of extended operation.

NUREG-1801 Consistency

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.M1, “ASME Section XI Inservice Inspections Program, Subsections IWB, IWC, and IWD,” and XI.M3, “Reactor Head Closure Studs” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Monitoring and Trending

Enhancements

Enhancements to the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program include revisions to existing activities credited for license renewal to ensure that inspections for the applicable aging effects are performed and any noted indications are appropriately evaluated. Additionally, applicable process control documents will be revised to ensure that new LBB analyses are performed following use of the Section XI flaw evaluation option or repair/replacement of Class 1 welds and CASS within the scope of the LBB analysis. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.M1, “ASME Section XI Inservice Inspections Program, Subsections IWB, IWC, and IWD,” and XI.M3, “Reactor Head Closure Studs,” is also provided below. During the 4th inspection interval, PBNP will use the 1998 edition through 2000 addenda (98A00) of ASME Section XI as modified by 10 CFR 50.55a, and approved Code Cases and Relief Requests. The evaluations of the individual program elements below includes consideration of the differences between the 98A00 code, as modified by approved Relief Requests, and the 1995 edition through 1996 addenda (95A96), which is the basis for the programs described in NUREG-1801, Sections XI.M1 and XI.M3.

Scope of Program

The ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Class 1 Piping/Components	Reactor Vessel
Pressurizer	Steam Generator

The ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection Program provides the requirements for inservice inspection, repair, and replacement of ASME Class 1, 2, and 3 components and their integral attachments, including all pressure retaining bolting. This program also includes the ISI of the reactor vessel closure studs and nuts, and includes the preventive measures of RG 1.65, “Material and Inspection for Reactor Vessel Closure Studs,” to mitigate cracking.

This element is consistent with the corresponding NUREG-1801, Section XI.M3, “Reactor Head Closure Studs,” aging management program element.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M1, “ASME Section XI Inservice Inspections Program, Subsections IWB, IWC, and IWD,” aging management program element. Section XI.M1 of NUREG-1801 references IWB-1220, IWC-1220, and IWD-1220 for the description of exempt components. The PBNP ISI Program uses the exemption criteria found in IWB-1220 of the 1989 Edition of Section XI, as required by 10 CFR 50.55a(b)(2)(xi). The 98A00 version of IWC-1220 deletes the exemption of Auxiliary Feedwater (AFW) System piping, vessels, pumps, valves, and their connections in piping between NPS 4 inch and NPS 1½ inch that had existed in the 95A96 version of the code. These exceptions to Section XI.M1 of NUREG-1801 are acceptable, because fewer components are exempted from the code requirements.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

For the reactor vessel head closure studs, preventive measures include avoiding the use of metal-plated stud bolting, and the use of acceptable surface treatments and stable lubricants to mitigate degradation.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Parameters Monitored or Inspected

The ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection Program detects degradation of components by using the examination and inspection requirements of ASME Section XI, Tables IWB-2500-1, IWC-2500-1, or IWD-2500-1 for Class 1, 2, or 3 components, respectively. RI-ISI alternative requirements apply to Categories B-J, B-F, C-F-1 and C-F-2. For pressure retaining bolting, the program monitors the effects of aging on the intended function of closure bolting, including loss of material, cracking, and loss of mechanical closure integrity. Components with pressure retaining bolting are inspected for signs of leakage.

This element includes exceptions to the corresponding NUREG-1801 aging management program elements. NUREG-1801 and the PBNP ISI Program reference different editions of the ASME Section XI code. The differences in the code editions applicable to ASME Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are discussed in the Detection of Aging Effects section below. PBNP meets the intent of these NUREG-1801 aging management program elements.

Detection of Aging Effects

The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of a component intended function. Inspection can reveal crack initiation and growth, loss of material due to corrosion, leakage of coolant, and indications of degradation caused by wear or stress relaxation, such as verification of clearances, settings, physical displacements, loose or missing parts, debris, wear, erosion, or loss of integrity at bolted or welded connections.

Components are examined and tested as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2 and 3 components, respectively. The tables specify the extent and schedule of the inspection and the examination methods for the components of pressure-retaining boundaries. RI-ISI alternative requirements apply to Categories B-J, B-F, C-F-1 and C-F-2.

In some cases, PBNP has submitted relief requests to the ASME Section XI examination requirements when fulfillment of these requirements is impossible, possible only with a major hardship, or when an alternative to the requirements is desired. In other cases, examinations that are in addition to ASME Section XI requirements (augmented examinations) are performed as a result of industry operating experience with certain types of degradation of components, or NRC generic communications. Approved relief requests and augmented inspections are listed in the ISI Program along with supporting information.

The program uses three types of examination; visual, surface, and volumetric in accordance with the general requirements of Subsection IWA-2000. Visual VT-1 examination detects discontinuities and imperfections, such as cracks, corrosion, wear, or erosion, on the surface of components. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test. Visual VT-3 examination (a) determines the general mechanical and structural condition of components and their supports by verifying parameters, such as clearances, settings, and physical displacements; and (b) detects discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion. Surface examination uses magnetic particle, liquid penetrant, or eddy current examinations to indicate the presence of surface discontinuities and flaws. Volumetric examination uses radiographic, ultrasonic, or eddy current examinations to indicate the presence of discontinuities or flaws throughout the volume of material.

The NDE techniques used to inspect Class 1 (Table IWB-2500-1), Class 2 (Table IWC-2500-1), and Class 3 (Table IWD-2500-1) components are consistent with the referenced ASME Section XI Code for those components. RI-ISI alternative requirements apply to Categories B-J, B-F, C-F-1 and C-F-2. The inservice inspections performed are consistent with the details of the NUREG-1801 aging management program elements, except for the differences discussed below.

The ISI Program for the 4th Inspection Interval will meet the requirements of the 1998 edition through 2000 addenda of ASME Section XI, as modified by 10 CFR 50.55a and approved Code Cases and Relief Requests. The periodicity of most examinations is once per interval, with the exception of examination categories B-P, C-H, and D-B (98A00 edition). These include visual VT-2 examination of all pressure retaining components during the system leakage test. The PBNP ISI Program specifies performance of the system leakage test once per refueling outage or each period for these examination categories, whichever applies.

PBNP will implement RI-ISI for Class 1 and 2 piping. RI-ISI can reduce the number of piping welds requiring examination based on an assessment of the probability and the safety consequences of a weld failure. The susceptibility assessment includes an evaluation for thermal and high cycle fatigue. RI-ISI can completely eliminate the surface examination of piping butt welds from the ISI Program. RI-ISI will require examination of a sample of susceptible risk significant small bore (< 4 inch) Class 1 and 2 piping. RI-ISI will require volumetric examination of non-socket welds and surface examination of socket welds in the sample. RI-ISI applies to Categories B-J, B-F, C-F-1 and C-F-2 (98A00 edition). All locations within Class 1 and Class 2 pressure boundaries will continue to receive a system pressure test and visual VT-2 examination as required by the code regardless of risk classification. RI-ISI does not apply to Class 3 components.

Examination requirements for Class 1, 2 and 3 pressure-retaining bolting are in accordance with ASME Section XI, Table IWB 2500-1 or IWC 2500-1. For Class 1 components, Table IWB 2500-1, examination category B-G-1, for bolting greater than 2 inches in diameter, specifies volumetric examination of studs and bolts and visual VT-1 examination of surfaces of nuts, washers, bushings, and flanges. Examination category B-G-2, for bolting 2 inches or smaller requires only visual VT-1 examination of surfaces of bolts, studs, and nuts. For Class 2 components, Table IWC 2500-1, examination category C-D, for bolting greater than 2 inches in diameter, requires volumetric examination of studs and bolts. Examination Categories B-P and C-H require VT-2 visual examination (IWA-5240) during system leakage testing of all pressure-retaining Class 1 and 2 components, according to Tables IWB 2500-1 and IWC 2500-1, respectively. The extent and schedule of inspections, in accordance with Tables IWB 2500-1 or IWC 2500-1, ensure detection of aging degradation before the loss of the intended function of the closure bolting.

Reactor vessel head closure studs are examined as required by Table IWB-2500-1, examination category B-G-1, “Pressure Retaining Bolting Greater than 2 inches in Diameter.” The reactor head closure studs are also visually examined during category B-P tests for all pressure-retaining components, which specify visual VT-2 examination during the system leakage test. PBNP's practice for reactor head closure studs is consistent with ASME Section XI, 1998 edition through 2000 addenda, which requires either a surface or volumetric examination but not both. Volumetric examinations are performed using Performance Demonstration Initiative (PDI) techniques in accordance with ASME Section XI, Appendix VIII and 10 CFR 50.55a.

This element includes exceptions to the corresponding NUREG-1801 aging management program elements, as discussed below.

The descriptions of the examination categories in NUREG-1801, Section XI.M1 are based on the 1989 edition of Section XI of the ASME Code with any differences in the examination categories in the 1995 edition through the 1996 addenda from those in the 1989 edition identified. Because the PBNP ISI Program is currently based on the 1998 edition through 2000 addenda of ASME Section XI for the fourth interval, this constitutes an exception to the NUREG-1801. However, 10 CFR 50.55a is periodically updated to endorse newer versions of ASME Section XI. The current revision to 10 CFR 50.55a endorses the 98A00 edition of ASME Section XI. Use of the 1998 edition through 2000 addenda of ASME Section XI was approved by SER 2001-0010 (Reference 5).

Section XI.M1 of NUREG-1801 also does not discuss Risk-Informed ISI, which will be implemented for Examination Categories B-F, B-J, C-F-1, and C-F-2 at PBNP for the fourth inspection interval. RI-ISI provides alternatives to the ASME Section XI requirements based on the susceptibility to various degradation mechanisms and the consequences of component failure.

NUREG-1801, Section XI.M1 states that welds selected during the first inspection interval are reexamined during successive inspection intervals. Approved Relief Request RR 8 modifies the sequence of examinations established in the previous inspection interval in a manner that reduces scaffold, insulation, and radiation exposure. The examinations will also be selected to coincide with the requirements of RI-ISI.

Approved Relief Request RR 10 allows examination of only one of the three vessels comprising the Regenerative Heat Exchanger. The bottom vessel will be examined because it is the most severely stressed. The 98A00 edition of the code does not require a volumetric examination of the inside radius section of pressurizer and steam generator nozzles. However, volumetric or visual examination of the inside radius is required by 10 CFR 50.55a(b)(2)(xxi)(A). These are exceptions to the NUREG-1801, Section XI.M1 Category B-D discussion.

Approved Relief Request RR 11 allows the use of Technical Specification surveillance testing as an alternative to the system leakage test of Class 3 pressure retaining components of the Emergency Diesel Generator (EDG) support systems. The auxiliary support systems addressed within the scope of this Relief Request include the starting air systems, fuel oil systems, and G03 and G04 glycol cooling systems. Successful EDG operability testing requires the associated subsystems to maintain pressure boundary integrity and, therefore, provides an equivalent level of quality and safety as those required by ASME Section XI, Category D-B. This is an exception to the Class 3 Components, Table IWD-2500-1 discussion in NUREG-1801, Section XI.M1.

Approved Relief Requests RR 5 and RR 6 relax the ASME Section XI requirements pertaining to the visual examination and corrective action associated with ASME Class 1, 2, and 3 bolted connections. RR 5 allows insulation to remain in place for the VT-2 visual examinations during system pressure tests. The alternative requirements of ASME Code Case N-533-1 will be applied. RR 6 eliminates the requirement of IWA-5250(a)(2) to remove and visually examine one bolt from bolted connections observed to be leaking during the performance of system pressure tests. The alternative requirements of ASME Code Case N-566-1 will be applied. Approved Relief Request RR 7 is applicable to Examination Categories B-G-1 and B-G-2. It proposes a relaxation of the IWA-5242(a) requirement to remove insulation from pressure retaining bolted connections for the performance of VT-2 examinations, if the bolting is resistant to boric acid corrosion. The alternative requirements of ASME Code Case N-616 will be applied. These three Relief Requests have been approved by the NRC and are exceptions to NUREG-1801, Section XI.M1.

Section XI.M1 of NUREG-1801 includes a Category B-H discussion regarding welded attachments for vessels. Category B-H was combined with Category B-K in the 95A96 edition of the code. Examination Category B-L-1 of the 95A96 edition of the code requires volumetric examination of all Class 1 pump casing welds. The 98A00 edition of the code only requires visual examination.

The version of ASME Section XI referenced in Section XI.M3 of NUREG-1801 requires volumetric and surface exams of reactor vessel head closure studs. The 98A00 version of the code only requires surface or volumetric exams, but not both. Since the issuance of RG 1.65, the sensitivity of volumetric examinations for detection of shallow surface defects has greatly improved. Surface examination of the studs has little added value, detecting only defects induced by handling rather than service induced defects. Elimination of the surface examination will reduce the potential for handling-induced defects to the studs.

Enhancements include revisions to existing activities credited for license renewal to ensure that inspections for the applicable aging effects are performed and any noted indications are appropriately evaluated.

Enhancements to plant process control procedures (e.g., design control, repair/replacement, ISI, and welding) will be made to ensure that use of the ISI flaw evaluation option or repair/replacement of welded connections and CASS in Class 1 components within the scope of Leak-Before-Break (LBB) analyses (i.e., main coolant loop, pressurizer surge line, accumulator injection lines, and residual heat removal lines) result in a new LBB analysis based on the replacement process and/or material properties. The new LBB analysis will account for thermal aging through the period of extended operation.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Monitoring and Trending

The examination schedules contained in the PBNP ISI Program meet the requirements of ASME Section XI, IWB-2412, IWC-2412, and IWD-2412, respectively (Inspection Program B). The PBNP ISI Program also meets the requirements for the extent and frequency of examinations specified by the 1998 Edition through 2000 addenda of ASME Section XI, IWB-2500-1, IWC-2500-1, and IWD-2500-1. If flaw indications or relevant conditions of degradation are found, additional examinations may be necessary.

In some cases, an evaluation in accordance with ASME Section XI, IWB-3100 or IWC-3100, may be used to qualify a component with flaw indications as acceptable for continued service. In such cases, the areas containing such flaw indications and relevant conditions are reexamined during the next three inspection periods of IWB-2410 for Class 1 components and for the next inspection period of IWC-2410 for Class 2 components. Examinations that reveal indications that exceed the acceptance standards described below are extended to include additional examinations in accordance with ASME Section XI, IWB-2430, IWC-2430, or IWD-2430 for Class 1, 2, or 3 components, respectively. The PBNP ISI Program meets the ASME Section XI 1998 edition through 2000 addenda with respect to inspection schedules, extent, method, and frequency of examination, flaw evaluations, and additional examinations.

For reactor vessel head closure studs, the inspection schedule of IWB-2400, and the extent and frequency specified in Table IWB-2500-1 provide timely detection of stud and nut degradation. For Class 1, 2, and 3 bolting, the examination schedules of ASME Section XI are effective and ensure timely detection of component degradation.

This element includes exceptions to the corresponding NUREG-1801 aging management program elements. As discussed above, the PBNP ISI Program uses the 98A00 edition of the ASME Section XI code instead of the 95A96 edition discussed in the NUREG-1801 programs. IWB-2420(b) of the 98A00 edition of the code allows the use of acoustic emission to monitor the growth of existing flaws in lieu of successive examinations during the next three inspection periods. The 95A96 edition of the code does not allow this option. Approved Relief Request RR 8 modifies the sequence of examinations established in the previous inspection interval in a manner that reduces scaffold, insulation, and radiation exposure. The examinations will also be selected to coincide with the requirements of RI-ISI.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Acceptance Criteria

Indications or relevant conditions that are not removed by repair, replacement, or surface conditioning are evaluated in accordance with IWB-3000, IWC-3000, or IWD-3000 for Class 1, 2, or 3 components, respectively. (Note: Every indication is evaluated, but they may be expected normal indications, such as the inside radius of a nozzle. These indications would not be evaluated against

IWX-3000, rather the indications would be evaluated as a normal condition and recorded in the ISI report.) Examination results are evaluated in accordance with IWB-3100 or IWC-3100 by comparing the results with the acceptance standards of IWB-3400 and IWB-3500 or IWC-3400 and IWC-3500 for Class 1 or Class 2 and 3 components, respectively. In rare cases, flaws exceeding the size of allowable flaws, as defined in IWB-3500 or IWC-3500, may be evaluated by using the analytical procedures of IWB-3600 or IWC-3600.

For reactor vessel head closure studs and Class 1 bolting, degradation is evaluated in accordance with IWB-3100 and the acceptance standards of IWB-3400 and IWB-3500. For Class 2 bolting, any degradation found is evaluated in accordance with IWC-3100 and the acceptance standards of IWC-3400 and IWC-3500.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants” (Reference 2), and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants” (Reference 6), as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Administrative Controls

The ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Operating Experience

A review of industry operating experience related to the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program revealed numerous instances of primary pressure boundary degradation. There have been numerous NRC communications including information notices, generic letters and bulletins. Most of the instances of degradation fall into the following categories:

- Boric acid corrosion caused by leakage at mechanical connections,
- Cracking caused by thermal fatigue,
- Degradation of bolting caused by stress corrosion cracking (SCC) of high-strength bolts or boric acid corrosion, or
- Leaks or cracks caused by primary water stress corrosion cracking (PWSCC) of Alloy 600 components.

Cracking caused by SCC of primary piping has been very rare in PWRs. NRC Information Notice (IN) 97-019 informed PWR utilities of a large circumferential crack in low-pressure safety injection system piping at Sequoyah-2 caused by SCC, that was discovered by a routine ISI ultrasonic examination. This is also one of relatively few large non-throughwall cracks discovered through routine ISI. Large non-throughwall cracks were also discovered by routine ISI in steam generator girth welds, as documented by NRC IN 85-065 and NRC IN 90-004.

Most of the indications found by examinations required by the ISI Programs at PBNP have been evidence of borated water leakage at mechanical joints, such as flange connections and valve bonnets. These indications were found via the VT-2 visual examinations during the system leakage test. In some of these cases, evidence of boric acid corrosion of bolting was discovered. Most of the leaks were corrected by tightening of bolting and replacing corroded bolts, if required. A search of Condition Reports and Maintenance Work Orders on reactor vessel head closure studs for both PBNP-1 and -2 revealed that no degradation of the studs or nuts has been detected. The examinations and inspections are conducted according to the requirements specified in Table IWB-2500-1.

The review of plant-specific operating experience revealed two instances where ISI examinations discovered flaws through means other than the system leakage test. Unacceptable flaw indications were discovered in each reactor vessel outlet nozzle-to-shell weld during the UT examination of reactor vessel welds at PBNP-1 in 1984. A fracture mechanics evaluation was performed that demonstrated that the flaws posed no threat to continued safe operation of the reactor vessel. The flaws have since been resized using more accurate techniques and have been determined to be within code allowances.

An example of degradation discovered by an examination performed as a result of industry operating experience was a crack discovered via radiography performed on a Masoneilan containment isolation valve seat cavity. The radiographic examination was performed as a result of industry operating experience with cracking caused by thermal cycling in similar valves. PBNP determined the affected valve remained operable based on an analysis that predicted very slow growth for this flaw.

The ISI Program at PBNP is frequently updated to account for industry operating experience. ASME Section XI is also revised every three years and addenda issued in the interim, which allows the code to be updated to reflect operating experience. The requirement to update the ISI Program to reference more recent editions of ASME Section XI at the end of each inspection interval, ensures the ISI Program reflects enhancements due to operating experience that have been incorporated into ASME Section XI.

NRC Inspection Report (IR) 99-017 documented an inspection of the Inservice Inspection Program. Activities inspected relating to ISI included radiographic testing (RT) examinations, non-destructive examination (NDE) procedures and examination data, contractor and licensee personnel qualifications, and a review of the long-term plan. No violations were identified, and the implementation of the program was found to meet ASME Code requirements.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no other issues or findings that could impact the effectiveness of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Conclusion

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.2 ASME Section XI, Subsections IWE & IWL Inservice Inspection Program

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program manages aging of (a) steel liners of concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets and moisture barriers; and pressure retaining bolting, and (b) reinforced concrete containments and unbonded post-tensioning systems. The primary inspection methods employed are visual examinations with limited supplemental volumetric and surface examinations, as necessary. Tendon anchorages and wires are visually examined. Tendon wires are tested to verify that minimum mechanical property requirements are met. Tendon corrosion protection medium is analyzed for alkalinity, water content and soluble ion concentrations. Pre-stressing forces are measured in sample tendons. Measured tendon lift-off forces are compared to predicted tendon forces calculated in accordance with Regulatory Guide 1.35.1. This program is in accordance with 10 CFR 50.55a and approved Code Cases and Relief Requests.

This program manages aging effects for:

- Carbon steel and miscellaneous polymeric materials and components that provide containment pressure boundary/leak-tight barrier function and are tested/inspected in accordance with 10 CFR 50, Appendix J and/or ASME Section XI, Subsection IWE,
- Containment tendons, and
- Concrete, which is inspected in accordance with ASME Section XI, Subsection IWL.

This program is credited by the Bolting Integrity Program for the inspection of pressure retaining bolting associated with the containment pressure boundary.

Relief Requests

There are no submitted Relief Requests awaiting NRC approval. The following Relief Requests have been approved by the NRC and have been incorporated into the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program as applicable:

- ERR-1 Seals and Gaskets

  Table IWE-2500-1, Items E5.10 and E5.20 require seals and gaskets to be visually examined once each inspection interval. ERR-1 allows leak-tightness testing of seals and gaskets in accordance with 10 CFR 50, Appendix J, Option B, as required by Category E-P, Item E9.40, as an alternative to the visual inspection requirements.

- ERR-2 Preservice of Reapplied Paint or Coatings

  ERR-2 allows application of paint or coatings in accordance with a quality controlled coatings application procedure instead of the preservice inspection of new paint or coatings required by IWE-2200(g). The program is not affected by this Relief Request.

- ERR-3 VT Prior to Paint or Coating Removal

  ERR-3 provides relief from the IWE-2500(b) requirement for a visual inspection of paint or coatings prior to removal. The program is not affected by this Relief Request.

- ERR-5 Successive Examination After Repair

  ERR-5 allows repaired flaws in Class MC components to be evaluated and accepted in accordance with IWA-4000 without performing successive examinations in accordance with IWE-2420(b) and IWE-2420(c). Successive examinations are not considered necessary because the failure mechanism which necessitated the repair is identified and corrected, and the repair receives preservice examination.

- ERR-6 Bolt Torque and Tension Testing

  IWE-2500, Table IWE-2500-1, Category E-G, Item E8.20 requires torque or tension testing of pressure retaining bolting that has not been disassembled and reassembled during the inspection interval. ERR-6 allows the use of the 10 CFR 50, Appendix J, Type B test as an alternative to the torque or tension tests.

- ERR-7 Venting Leak Chase Channels

During containment integrated leak rate testing, IWE 2500, Table IWE-2500-1, Category E-P, Item E9.10, Note (2) requires containment liner leak chase channels be unplugged or tested in accordance with 10 CFR 50, Appendix J, Type B testing. ERR-7 provides relief from this requirement.

- ERR-9 NDE Personnel Certification and Qualification

  ERR-9 allows the qualification and certification of NDE personnel to a written practice in accordance with SNT-TC1A instead of CP-189 which is required by IWA-2300.

- LRR-1 Remote VT of Class CC

  IWA-2210 and Table IWA-2210-1 impose minimum illumination and maximum direct examination distance requirements to the containment inspections required by IWL-2310. LRR-1 relaxes these requirements as long as conditions or indications for which the visual examinations are performed are detectable at the chosen distance and illumination.

- LRR-2 General Visual Examination of Class CC

  IWL-2510(a) requires that concrete surfaces and tendon end anchorage areas be VT-3C visually examined for evidence of damage or degradation. LRR-2 allows a general visual inspection of inaccessible concrete surfaces, excluding those areas exempted by IWL-1220, instead of the code required VT-3 examination. A VT-1C examination on the tendon end anchorages under Category L-B, Item 2.30, as required by IWL-2521, is also required.

NUREG-1801 Consistency

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program is an existing program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.S4, “10 CFR Part 50 Appendix J,” and is consistent with, but includes exceptions to, Sections XI.S1, “ASME Section XI, Subsection IWE,” and XI.S2, “ASME Section XI, Subsection IWL” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Parameters Monitored or Inspected
- Detection of Aging Effects
- Monitoring and Trending

- Acceptance Criteria

Enhancements

Enhancements to the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program include revisions to the containment airlock door seal inspection and replacement procedure to provide more detailed documentation, and a methodology for trending and comparison of inspection results to acceptance criteria. The PBNP “CLRT Program Basis Document” will be revised to clarify that test results are documented in accordance with 10 CFR Part 50, Appendix J. The PBNP “ISI IWL Program” document will be revised to clarify that yield strength will also be determined for tendon wire samples in accordance with IWL-2523.2. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.S4, “10 CFR Part 50 Appendix J,” XI.S1, “ASME Section XI, Subsection IWE,” and XI.S2, “ASME Section XI, Subsection IWL,” is also provided below. PBNP uses the 1992 Edition with 1992 Addenda of ASME Section XI, Subsections IWE and IWL, as modified by 10 CFR 50.55a and approved Relief Requests, for the current inspection interval. The evaluations of the individual program elements below include consideration of the effects of the approved Relief Requests on the code requirements discussed in the NUREG-1801 programs.

Scope of Program

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Containment Unit 1/2 Building Structure

The scope of this program includes the containment structure and all components that make the structure a vessel, which contains the radioactive materials released should a loss of coolant accident occur (i.e., leakage rate to be within the values given in the Technical Specifications). This implies that the containment structure be of adequate construction such that it will safely withstand the maximum calculated internal pressure and that it will be able to perform its function throughout the life of the structure, including the period of extended operation. To accomplish this, inspections and testing are conducted on the accessible components that make up the containment structure, as follows:

- Inspection of the steel containment liner and its integral attachments; containment hatches and air locks, seals, gaskets and moisture barriers; and containment pressure retaining bolting (ASME Section XI, Subsection IWE),
- Inspections of the reinforced concrete and the unbonded post-tensioning systems, and testing of tendon wires to verify that they are within the required pre-stress values (ASME Section XI, Subsection IWL), and
- Containment leak rate testing, which includes the containment integrated leakage rate and the local leakage rates across each containment penetration pressure retaining boundary, including the containment isolation valves (10 CFR Part 50, Appendix J, Option B).

ASME Section XI, Subsections IWE & IWL exempts inaccessible portions of the components from inspections. However, 10 CFR 50.55a states that the licensee is to evaluate the acceptability of these inaccessible components when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. As part of the existing program, these evaluations are performed when required based on inspection results.

This element is consistent with the three corresponding NUREG-1801 aging management program elements.

Preventive Actions

This is a monitoring program and there are no preventive actions associated with ASME Section XI, Subsection IWE and 10 CFR 50, Appendix J. With regards to ASME Section XI, Subsection IWL, the containment tendons were filled with grease to prevent the tendon wires and the tendons from corroding. The grease is periodically analyzed for alkalinity, water content and soluble ion concentrations in accordance with Table IWL-2525-1.

This element is consistent with the three corresponding NUREG-1801 aging management program elements.

Parameters Monitored or Inspected

Components are inspected, monitored, and tested per the requirements of ASME Section XI, Subsections IWE & IWL and 10 CFR 50, Appendix J, Option B as follows:

- Visual VT-3 inspections of accessible containment steel surfaces for evidence of cracking, discoloration, wear, pitting, discontinuities, excessive erosion/corrosion, and signs of surface irregularities.
- Visual VT-1 and volumetric inspections of containment surfaces requiring augmented examinations for evidence of coating or paint flaking, blistering, peeling, discoloration or other signs of distress.
- Visual VT-3 inspections of moisture barriers (caulking) for wear, damage, erosion, corrosion, surface cracks, and other defects, which may violate the leak tight integrity.
- Visual VT-1 inspections of pressure retaining bolting for cracks or crack like indications, deformed or sheared threads, missing or loose bolting, and general corrosion.
- All concrete surfaces, and concrete surfaces surrounding tendon anchorages are inspected for cracks, exposed reinforcing steel, corrosion or corrosion staining, drummy areas, settlement or deflections, scaling and leaching/chemical attack.
- Tendon grease is analyzed for water content, chlorides, nitrates, sulfides, and reserve alkalinity.
- A sample of tendon wires are tested for yield strength, ultimate strength, and elongation.
- The pre-stress force of inspection sample tendons are measured by lift-off or an equivalent test.
- Tendon anchorage hardware is inspected for active corrosion, cracking, physical damage, and missing wires/detached buttonheads.
- The containment is pressurized in order to perform an integrated leak rate test to monitor the leakage rates through the containment liners, associated welds, penetrations, fittings, and other access openings.
- Local leak rate testing is performed to identify the rate for the individual leak paths associated with each penetration.

The inspections identified above are performed in accordance with approved NDE procedures. For example, prior to an ILRT, a visual examination of 100% of the accessible interior and exterior surfaces of the containment is performed. The parameters monitored during this exam include cracks in the concrete, bulged areas, attachment welds between structural attachments and the pressure retaining boundary, displacement between floor slabs, cracks in floor expansion joint filler material, and telltales of water in-leakage on floor, wall or ceiling surfaces.

This element is consistent with the NUREG-1801, Section XI.S4, “10 CFR Part 50 Appendix J,” aging management program element.

This element includes exceptions to the NUREG-1801, Sections XI.S1, “ASME Section XI, Subsection IWE,” and XI.S2, “ASME Section XI, Subsection IWL,” aging management program elements. NUREG-1801, Section XI.S1 evaluates the 1992 Addition with 1992 Addenda of the ASME code. PBNP utilizes this edition and addenda, but as modified by approved Relief Requests. The approved Relief Requests include the elimination of VT-3 examinations of seal and gaskets (ERR-1), required bolt torque or tension tests (ERR-6), and venting of leak chase channels during integrated leak rate tests (ERR-7). NUREG-1801, Section XI.S2 states that IWL-2510 uses ACI 201.1R-77 as a source of information for concrete degradation. The “ISI IWL Program” at PBNP uses ACI 201.1R-68 (Reference 7) as a reference for concrete degradation. This is consistent with the 92 Edition through 92 Addenda of IWL-2510 and Table IWA-1600-1.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Detection of Aging Effects

The frequency and scope of the inspections/tests ensure that the applicable aging effects will be detected before they would compromise the design-basis requirements. The inservice examinations and the pressure tests are performed in accordance with the applicable codes. All the components are inspected and/or leak rate tested at the specified intervals. The frequency of the examinations on the structural components are specified in 10 CFR 50.55a and Subsections IWE & IWL of the 1992 Edition with 1992 Addenda of ASME Section XI. The containment CLRT program is effective in detecting degradation of containment shells, liners, and components that comprise the pressure boundary, including seals and gaskets.

This element is consistent with the NUREG-1801, Section XI.S4, “10 CFR Part 50 Appendix J,” aging management program element.

This element includes exceptions to the NUREG-1801, Sections XI.S1, “ASME Section XI, Subsection IWE,” and XI.S2, “ASME Section XI, Subsection IWL,” aging management program elements. An exception to the NUREG-1801, Sections XI.S1 and XI.S2 elements is that approved Relief Request ERR-9 allows the qualification and certification of NDE personnel to a written practice in accordance with SNT-TC1A instead of CP-189 which is required by IWA-2300. Although, PBNP currently qualifies and certifies NDE personnel in accordance with CP-189 as a result of NMC fleet standardization efforts. Additional exceptions to the NUREG-1801, Section XI.S2 element are due to approved Relief Requests, which relax the illumination and direct examination distance requirements of IWA-2210 (LRR-1) and allow a general visual inspection of inaccessible concrete surfaces instead of the VT-3 examination required by IWL-2510(a) (LRR-2).

The containment airlock door seal inspection and replacement procedure will be enhanced to provide more detailed documentation, and a methodology for trending and comparison of inspection results to acceptance criteria.

An enhancement will be made to the PBNP “CLRT Testing Program Basis Document” to clarify that test results are documented in accordance with 10 CFR Part 50, Appendix J.

An enhancement will also be made to the PBNP “ISI IWL Program” document to clarify that yield strength for tendon wire samples will be determined in accordance with IWL-2523.2.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Monitoring and Trending

Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements specified in the PBNP “IWL Containment Inspection Program.” All accessible surfaces of the containment pressure boundary components are monitored for age related degradation on a scheduled basis in accordance with NDE procedures. The general visual examination procedure requires re-examination of degraded areas previously identified. Inaccessible areas of concrete are evaluated for acceptability when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. In addition, examinations are performed on 100% of the surface areas of components identified by the IWE Responsible Engineer as likely to experience accelerated degradation or aging.

Furthermore, the PBNP “IWE Containment Inspection Program” specifies that when component examination results require evaluation of flaws or evaluation of areas of degradation, and the component is found to be acceptable for continued service, the areas containing such flaws or degradation are re-examined during the next two inspection periods. In accordance with the PBNP “IWE Containment Inspection Program,” augmented examination of these areas is no longer required when the reexaminations reveal that the flaws or areas of degradation remain essentially unchanged for three consecutive inspection periods.

The IWE Containment Inspection Program deviates from the requirements of IWE-2430 by following the alternative examination requirements allowed by 10 CFR 50.55a(b)(2)(ix)(D). If the examinations reveal flaws or areas of degradation exceeding the acceptance standards of IWE-3400-1, an evaluation is performed to determine whether additional component examinations are required.

Periodic verification of the leak-tight integrity of the primary containment and penetrations is accomplished by the testing performed in accordance with the requirements of 10 CFR Part 50, Appendix J, Option B. These inspection results are documented and the records are maintained for future reference.

The PBNP “IWL Containment Inspection Program” requires an evaluation if consecutive surveillances of pre-stressing forces for the same tendon, or tendons in a group, indicate a trend of pre-stress loss such that the tendon force would be less than the minimum design pre-stress requirements prior to the next scheduled inspection. In addition to the random sampling used for tendon examination in the PBNP “IWL Containment Inspection Program,” one tendon of each type is designated as a common tendon. Each common tendon is then examined during each inspection.

This element is consistent with the aging management program elements of NUREG-1801, Sections XI.S4, “10 CFR Part 50 Appendix J,” and XI.S2, “ASME Section XI, Subsection IWL.”

This element includes exceptions to the NUREG-1801, Section XI.S1, “ASME Section XI, Subsection IWE,” aging management program element. The exception is that successive examination of repairs is not performed. This is allowed by approved Relief Request ERR-5.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Acceptance Criteria

Examinations and evaluations are performed in accordance with the requirements of ASME Section XI, Subsection IWE, which provides acceptance standards for the containment pressure boundary components. The acceptance standards delineated in NDE procedures for pressure boundary components are consistent with the ASME Section XI, Subsection IWE. Inspections that reveal evidence of degradation exceeding these acceptance standards are subject to additional inspections to determine the nature and extent of the condition. Areas that are suspect require an evaluation, repair, or replacement.

NDE procedures provide acceptance criteria for containment components consistent with those listed in ASME Section XI, Subsection IWL. The acceptance criteria found in these documents are based on guidance provided in ACI 201.1R-68 (Reference 7) and ACI 349.3R-96 (Reference 10). In addition, all documented areas of degradation are evaluated to determine if there exists deterioration of components that could jeopardize structural integrity or leak tightness of the containment. Leakage rate acceptance criteria meeting the requirements of 10 CFR Part 50, Appendix J are defined in the PBNP “CLRT Testing Program Basis Document.”

The PBNP “IWL Containment Inspection Program” provides directives for evaluating the post-tensioning system inspection results against quantitative acceptance criteria for tendon pre-stress force and elongation, tendon wire or strand samples, and tendon grease.

This element is consistent with the aging management program elements of NUREG-1801, Sections XI.S4, “10 CFR Part 50 Appendix J,” and XI.S1, “ASME Section XI, Subsection IWE.”

This element includes exceptions to the NUREG-1801, Section XI.S2, “ASME Section XI, Subsection IWL,” aging management program element. NUREG-1801, Section XI.S2 states that IWL-2510 uses ACI 201.1R-77 as a source of information for concrete degradation. The PBNP “ISI IWL Program” at

PBNP uses ACI 201.1R-68 as a reference for concrete degradation. This is consistent with the 1992 Edition through 1992 Addenda of IWL-2510 and Table IWA-1600-1.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the three corresponding NUREG-1801 aging management programs elements.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the three corresponding NUREG-1801 aging management programs elements.

Administrative Controls

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the three corresponding NUREG-1801 aging management programs elements.

Operating Experience

Plant specific operating experience has shown that degradation has occurred. For example: failed tendon wires, missing or broken components found in the tendon hardware, degraded concrete in containment structure, corroded containment liner, and corrosion of penetrations inside of containment. In addition, industry operating experience and NRC information notices have documented areas of concern regarding containment liner plate, concrete, and tendon degradation. PBNP evaluates these concerns, takes corrective actions as appropriate, and adjusts the program accordingly.

Plant-specific operating experience was reviewed and revealed that degradation has occurred in the Unit 1 and 2 containment liners at the 8 foot elevation due to poor condition of the moisture barriers. The degradation consisted of general corrosion and pitting. The moisture barriers have since been replaced. Several mechanical penetrations inside the Unit 1 and 2 containments have shown indications of general corrosion and/or peeling paint. Corrosion was also found in the Unit 1 and 2 Containment Sump A at the interface between the containment liner plates and containment floor slabs.

Inspections performed on the containment tendons have discovered the following degradations:

- Broken wires,
- Wires with 2% to 4% less than expected pre-stress,
- Presence of nitrates in grease,
- Cracked button-head, missing button-heads,
- Tendon void of 9.7% of grease volume,
- More grease added than removed in some instances.

These occurrences of degradation have been evaluated and corrective action has been taken, as required.

During the preparations for the 28th year tendon surveillance, it was discovered that the designated “common” or “control” tendons (i.e., those tendons in each group that are tested every surveillance in order to establish the trend of pre-stress force for that group) had been retensioned during each preceding surveillance. Periodic retensioning of these tendons did not allow an accurate determination of pre-stress force relaxation trends. New common tendons, which had not been previously retensioned, were selected for the 28th year surveillance. These tendons will be tested in future surveillances in order to establish valid pre-stress force trends. The NRC was advised of this situation in a June, 1999 letter (Reference 11).

Industry operating experience and NRC information notices have documented occurrences of corrosion in steel containment shells and degradation in containment pre-stressing systems(References 32 and 33).

The implementing procedures that support this program have been effective in maintaining the intended functions of the components that make up the containment structure. A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program. Nuclear Oversight performed an assessment of the containment leak rate test program during the fourth quarter of 2002 and concluded that the local leak rate testing program complies with the requirements of 10 CFR 50, Appendix J. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the three corresponding NUREG-1801 aging management program elements.

Conclusion

The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program provides reasonable assurance that the applicable aging effects will be managed such that containment structures and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. Containment visual examination of steel and concrete components that are part of the leak tight barrier have been conducted at PBNP since initial start-up. These examinations are performed in accordance with ASME Section XI, Subsections IWE & IWL. In addition, leak rate testing is performed in accordance with 10 CFR Part 50, Appendix J, Option B. As part of the ASME Section XI, Subsection IWL inspection program, the tendon wires that supply the pre-stressing forces on the containment concrete structure are examined and tested. The visual inspections verify the condition of all anchorage components and examine for corrosion, pitting, cracking, distortion, presence of water, and other indications. The surrounding concrete is also examined. The combination of these inspections and tests are conducted to verify that the primary reactor containment will continue to perform its intended function.

Although the visual inspections are general in nature, they are intended to detect areas of widespread pitting, gouges, cracks, rust, flaking, and other visible indications on welds or structural components. Detailed inspections and evaluations are performed if gross discrepancies are detected. All conditions noted during the inspections of the containment, whether or not they are considered to require further review, are documented in inspection reports. The inspection procedures provide guidelines in accordance with NEI 94-01.

B2.1.3 ASME Section XI, Subsection IWF Inservice Inspection Program

Program Description

The ASME Section XI, Subsection IWF Inservice Inspection Program manages aging effects for Class 1, 2, and 3 component supports (Reference 3). The primary inspection method employed is visual examination. Criteria for acceptance and corrective action are in accordance with ASME Section XI, Subsection IWF. Degradation that potentially compromises the function or load capacity of the support, including bolting, is identified for evaluation. Supports requiring corrective action are re-examined during the next inspection period. This program is in accordance with 10 CFR 50.55a and approved Code Cases and Relief Requests.

The PBNP Inservice Inspection (ISI) Program for the fourth (4th) ten-year interval, which began on July 1, 2002 for both PBNP-1 and PBNP-2, will meet the 1998 edition through 2000 addenda (98A00) of ASME Section XI, Subsection IWF as modified by 10 CFR 50.55a and approved Code Cases and Relief Requests. Table IWF-2500-1 of the 98A00 of ASME Section XI lists the areas of component supports to be examined, and the method, extent and frequency of examination for each area. The examination scope provided by Table IWF-2500-1 specifies the percentage of supports that must be examined. The percentages of supports required to be examined are 25%, 15%, and 10% for Class 1, 2, and 3 piping supports, respectively, and 100% for non-piping supports. For supports other than piping supports, the supports of only one component of a group having similar design, function, and service must be examined. Supports of piping and other items exempted from volumetric or surface examination are also exempt.

As specified by Table IWF-2500-1, the program uses VT-3 visual examination for detection of degradation. The performance requirements for VT-3 examination are provided in IWA-2213. Per IWA-2213, VT-3 examinations are conducted to determine the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacement, and to detect discontinuities and imperfections, such as loss of integrity of bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion. Acceptance standards for supports are given by IWF-3410. Unacceptable conditions include:

- Deformation or structural degradation of fasteners, springs, clamps, or other support items;
- Missing, detached, or loosened support items;
- Arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces;

- Improper hot or cold positions of spring supports and constant load supports;
- Misalignment of supports; and
- Improper clearances of guides and stops.

This program is credited by the Bolting Integrity Program for the inspection of bolting and fasteners within the scope of ASME Section XI, Subsection IWF.

Relief Requests

The following Relief Requests have been approved by the NRC and have been incorporated into the ASME Section XI, Subsection IWF Inservice Inspection Program:

- RR 1 - Altering the Date of the Start of the Fourth Inspection Interval

  SER 2001-0005 approved this Relief Request, which aligned the inspection intervals to be the same for PBNP-1 and -2. The fourth interval for both units began on July 1, 2002.

- RR 2 - Use of Later Code Editions

  SER 2001-0010 approved this Relief Request, which allows the use of the 1998 Edition, 2000 Addenda of the ASME Section XI Code for both units during the fourth inspection interval.

- RR 8 - Successive Inspections (Code Case N-624)

  IWF-2420(a) requires the sequence of component support examinations that was established during the first inspection interval to be repeated during each successive inspection interval to the extent practical. SER 2003-0007 approved this Relief Request, which allows the sequence of examinations established in the previous inspection interval to be modified in a manner that reduces scaffold, insulation, and radiation exposure. This Relief Request has been superseded by Revision 13 of RG 1.147, “Inservice Inspection Code Case Acceptability ASME Section XI.”

The following Relief Requests have no effect on the ASME Section XI, Subsections IWF Inservice Inspection Program:

- RR 3 - Risk Informed Examination of Class 1 and Class 2 Piping Butt Welds (Code Case N-578 and EPRI TR-112657).
- RR 4 - Alternate Requirements to Repair and Replacement Documentation Requirements and Inservice Inspection Summary Report Preparation and

Submission as Required by IWA-4000 and IWA-6000 (Code Case N-532-1). This Relief Request has been superseded by Revision 13 of RG 1.147.

- RR 5 - Alternate Requirements for VT-2 Visual Examination of Class 1, 2, and 3 Insulated Pressure-Retaining Bolted Connections (Code Case N-533-1). This Relief Request has been superseded by Revision 13 of RG 1.147.
- RR 6 - Corrective Action for Leakage Identified at Bolted Connections (Code Case N-566-1). This Relief Request has been superseded by Revision 13 of RG 1.147.
- RR 7 - Alternative Requirements for VT-2 Visual Examination of Class 1, 2, and 3 Insulated Pressure-Retaining Bolted Connections, Section XI, Division 1 (Code Case N-616). This Relief Request has been superseded by Revision 13 of RG 1.147.
- RR 9 - Alternative to Welding and Brazing Performance Qualification Requirements.
- RR 10 - Relief from Regenerative Heat Exchanger Examinations.
- RR 11 - Emergency Diesel System VT-2 Examination.
- RR 12 Request for Alternative to ASME Section XI, Appendix VIII, Supplement 10. This Relief Request has been submitted and is still pending NRC approval.

NUREG-1801 Consistency

The ASME Section XI, Subsection IWF Inservice Inspection Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.S3, “ASME Section XI, Subsection IWF” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 program element assumptions:

- Scope of Program
- Detection of Aging Effects

Enhancements

Enhancements to the ASME Section XI, Subsection IWF Inservice Inspection Program include revising existing implementing documents to include cracks as recordable conditions for component supports. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the ASME Section XI, Subsection IWF Inservice Inspection Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.S3, “ASME Section XI, Subsection IWF,” is also provided below. PBNP uses the 1998 Edition through 2000 Addenda (98A00) of ASME Section XI, Subsection IWF, as modified by 10 CFR 50.55a and approved Code Cases and Relief Requests, for the current inspection interval. The evaluations of the individual program elements below includes consideration of the differences between the 98A00 code, as modified by approved Relief Requests, and the 1995 Edition through the 1996 Addenda (95A96), which is the basis for the program described in NUREG-1801, Section XI.S3.

Scope of Program

The ASME Section XI, Subsection IWF Inservice Inspection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Component Supports Commodity Group

The program applies to ASME Section XI Class 1, 2, and 3 component supports.

For the 1998 edition through 2000 addenda of ASME Section XI, which is applicable to the fourth inspection interval at PBNP-1 and PBNP-2, the examination scope provided by Table IWF-2500-1 specifies the percentage of supports that must be examined. The percentages of supports required to be examined are 25%,15%, and 10%, for Class 1, 2, and 3 piping supports, respectively, and 100% for non-piping supports. For supports other than piping supports, the supports of only one component of a group having similar design, function, and service must be examined. Table IWF-2500-1 also lists the areas of component supports to be examined, and the method, extent and frequency of examination for each area.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. One exception is that PBNP uses the 1998 edition through the 2000 addenda of the ASME Section XI code instead of the 1995 edition through 1996 addenda which is specified in the NUREG-1801 program. The 1998 edition through 2000 addenda encompasses the requirements of the 1995 edition through 1996 addenda. In addition, the NUREG-1801 program includes Class MC supports within the program scope. 10 CFR 50.55a does not require inspection of Class MC supports under Subsection IWF and PBNP does not include these inspections in its ISI Program. There are no components within the scope of license renewal which rely on IWF Class MC inservice inspections for the management of aging effects. Applicable portions of the containment polar crane rail supports and dome trusses are inspected under the Structures Monitoring Program.

Another exception is related to approved Relief Request RR 8 regarding successive inspections. RR 8 modifies the requirements of IWF-2420(a) to allow the sequence of examinations established in the previous inspection interval to be changed in a manner that reduces scaffold, insulation, and radiation exposure. The percentage requirements of Table IWF-2410-2 will continue to be satisfied in accordance with Code Case N-624.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

No preventive actions are specified; the ASME Section XI, Subsection IWF Inservice Inspection Program is a condition monitoring program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The parameters monitored or inspected include corrosion, deformation, misalignment, improper clearances, improper spring settings, damage to close tolerance machined or sliding surfaces, and missing, detached, or loosened support items. Component support bolting is inspected for indication of potential problems, including obvious signs of corrosion and rust. Although not specifically listed in the IWF-3400 acceptance standards, visual inspections are expected to identify cracks. Plant procedures, which describe VT-3 visual examinations, include cracks as recordable conditions for component supports.

Section IWF-2500 specifies the examination requirements for the following aspects of component supports:

- Mechanical connections to pressure-retaining components and building structure;
- Weld connections to building structure;
- Weld and mechanical connections at intermediate joints in multi-connected integral and non-integral supports;
- Clearances of guides and stops, alignment of supports, and assembly of support items;
- Spring supports and constant load supports;
- Accessible sliding surfaces; and
- Hot or cold position of spring supports and constant load supports.

In Table IWF-2500-1, the examination method, acceptance standard, sample of examination and frequency of examination are given for:

- Class 1 Piping Supports;
- Class 2 Piping Supports;
- Class 3 Piping Supports; and
- Supports Other than Piping Supports (Class 1,2, and 3).

Existing implementing documents will be revised to include cracks as recordable conditions for component supports.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

As specified by Table IWF-2500-1, the program uses VT-3 visual examination for the detection of aging effects. The performance requirements for VT-3 visual examinations are provided in IWA-2213. Per IWA-2213, “VT-3 examinations are conducted to determine the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacements; and to detect discontinuities and imperfections, such as loss of integrity of bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion.” The qualified VT-3 examiner uses judgment in assessing general corrosion. Observed degradation is documented and evaluated if loss of structural capacity is suspected.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 states that the complete inspection scope is repeated every 10-year inspection interval. Approved Relief Request RR 8 modifies the requirements of IWF-2420(a) to allow the sequence of examinations established in the previous inspection interval to be changed in a manner that reduces scaffold, insulation, and radiation exposure. The percentage requirements of Table IWF-2410-2 will continue to be satisfied in accordance with Code Case N-624.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

Unacceptable conditions, as described in IWF-3400, are noted for correction or further evaluation. However, there is no requirement to monitor or report progressive, time-dependent degradation.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

The program utilizes the acceptance standards for visual examination specified in IWF-3400. In IWF-3410 (b)(5), “roughness or general corrosion which does not reduce the load bearing capacity of the support” is given as an example of a “non-relevant condition,” which requires no further action. IWF-3410 (a) identifies the following conditions as unacceptable:

- Deformations or structural degradations of fasteners, springs, clamps, or other support items;
- Missing, detached, or loosened support items;
- Arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces;
- Improper hot or cold positions of spring supports and constant load supports;
- Misalignment of supports; and
- Improper clearances of guides and stops.

Discovery of unacceptable conditions that require corrective action triggers an expansion of the inspection scope in accordance with IWF-2430. Reexamination of supports requiring corrective actions or acceptance by evaluation shall be performed during the next inspection period, in accordance with IWF-2420(b). Indications of cracking in component support bolting will warrant replacement of the cracked bolt.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The ASME Section XI, Subsection IWF Inservice Inspection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

A review of industry and plant–specific operating experience was conducted. NRC Information Notice 80-36 notified utilities of the potential for stress corrosion cracking (SCC) of high strength component support bolts. High strength (> 150 ksi yield) component support bolting at PBNP is used in pinned connections associated with the Steam Generator, Reactor Coolant Pump, and

Reactor Vessel supports and is loaded only in shear. SCC of these bolts is not a concern because the bolts have no preload stress and are not located in an aggressive environment. Corrosion of supports has also been identified at other nuclear plants, particularly in supports located outdoors at saltwater-cooled plants (Reference 3).

The most common relevant condition discovered by the ASME Section XI, Subsection IWF Inservice Inspection Program at PBNP has been loose fasteners in supports. Loose fasteners are a maintenance issue, rather than a sign of age-related degradation. To date, these examinations have been effective in managing aging effects for ASME Class 1, 2, and 3 component supports.

A 1999 NRC Inspection Report contained a finding related to inservice inspection of component supports. The NRC inspection team found two pipe supports in the Auxiliary Feedwater pump room that had gaps between the baseplate and the concrete wall that exceeded the criteria specified in plant procedures. The procedure had been recently revised to include acceptance criteria for such gaps, but the examiners were not yet using the newly revised procedure. PBNP issued a Condition Report and performed an operability determination to evaluate the support's capability to adequately transfer the design loads to the building structure. The operability determination concluded the support was operable and that no further action was required, and the Condition Report was closed. The NRC inspection team concluded that PBNP was appropriately evaluating and prioritizing the identified support gaps.

Another 1999 NRC Inspection Report documented an inspection of the Inservice Inspection Program. No violations were identified, and the implementation of the program was found to meet ASME code requirements. No specific activities related to the examination of component supports were evaluated during the NRC inspection; however, these activities are part of the overall Inservice Inspection program, which was found to be in compliance with regulatory requirements.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no other issues or findings that could impact the effectiveness of the ASME Section XI, Subsection IWF Inservice Inspection Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The ASME Section XI, Subsection IWF Inservice Inspection Program provides reasonable assurance that aging effects will be managed such that Class 1, 2, and 3 component supports within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.4 Bolting Integrity Program

Program Description

The Bolting Integrity Program manages the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Section XI related bolting and generic guidance regarding material selection, thread lubrication and assembly of bolted joints. The program considers the guidelines delineated in NUREG-1339 for a bolting integrity program, EPRI NP-5769 (Reference 37) (with the exceptions noted in NUREG-1339) for safety related bolting, and EPRI TR-104213 (Reference 38) for non-safety related bolting. The Bolting Integrity Program credits seven separate aging management programs for the inspection of bolting. The seven aging management programs are: (1) the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, (2) ASME Section XI, Subsections IWE & IWL Inservice Inspection Program, (3) ASME Section XI, Subsection IWF Inservice Inspection Program, (4) Systems Monitoring Program, (5) Structures Monitoring Program, (6) Reactor Vessel Internals Program, and (7) the Periodic Surveillance and Preventive Maintenance Program.

It is recognized that the Boric Acid Corrosion Program manages aging effects for structures and components, including threaded fasteners, as a result of borated water leakage. However, it is not included as a credited program because NUREG-1801 (e.g., Section VII, Item I.1-a) does not rely on the Bolting Integrity Program to manage corrosion due to boric acid leakage. NUREG-1801 does rely on the Bolting Integrity Program to manage all other aging effects for bolting, which are managed by the seven credited programs identified above.

The scope of the credited programs for bolting is summarized below.

- The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides the requirements for inservice inspection of ASME Section XI, Class 1, 2, and

3 pressure retaining bolting. This program also specifically discusses the inspection and lubrication of the reactor vessel head closure studs.

- The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program provides the requirements for the inspection of pressure retaining bolting associated with the containment pressure boundary.
- The ASME Section XI, Subsection IWF Inservice Inspection Program provides the requirements for the inspection of bolting associated with supports for ASME Section XI, Class 1, 2, and 3 piping and components.
- The Systems Monitoring Program provides the requirements for the inspection of bolting within the scope of license renewal in addition to the bolting within the scope of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program.
- The Structures Monitoring Program provides the requirements for the inspection of all structural and component support bolting within the scope of license renewal in addition to the bolting within the scope of the ASME Section XI, Subsections IWF Inservice Inspection Program. Other bolting and fasteners are also included within the scope of this program, such as those used in supports for cable trays, conduits, and cabinet supports.
- The Reactor Vessel Internals Program provides the requirements for the inspection of bolting internal to the reactor vessel. In addition to the requirements of ASME Section XI, Subsection IWB, this program monitors for loss of preload caused by stress relaxation of bolted joints and specifically addresses cracking in baffle/barrel former bolts.
- The Periodic Surveillance and Preventive Maintenance Program provides the requirements for the inspection of other fasteners (i.e., fasteners not falling within the scope of the previous six programs) within the scope of license renewal. This program also provides controls on deferrals, cancellations and frequency changes for callups utilized by any of the other credited programs.

NUREG-1801 Consistency

The Bolting Integrity Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M18, “Bolting Integrity” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Preventive Actions
- Detection of Aging Effects
- Monitoring and Trending
- Acceptance Criteria

Enhancements

Enhancements to the Bolting Integrity Program include the incorporation of applicable guidance from NUREG-1339, EPRI NP-5769, and EPRI TR-104213 into existing plant implementing documents dealing with bolted joints. Additional enhancements include revisions to existing implementing documents to include specific inspections for the aging effects being managed by this program. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Bolting Integrity Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M18, “Bolting Integrity,” is also provided below.

Scope of Program

The Bolting Integrity Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Heating Steam
Chemical and Volume Control	Main and Auxiliary Steam
Circulating Water	Non-Class I RCS Components
Class 1 Piping/Components	Plant Air
Component Cooling Water	Pressurizer
Containment Hydrogen Detectors and Recombiners	Residual Heat Removal

Containment Isolation Components	Safety Injection
Containment Spray	Service Water
Containment Ventilation	Spent Fuel Cooling
Emergency Power	Steam Generator
Essential Ventilation	Treated Water
Feedwater and Condensate	Waste Disposal
Fire Protection	

The program covers all bolting and fasteners within the scope of license renewal, including safety related bolting, bolting for NSSS component supports, bolting for other pressure retaining components, and structural bolting. The Bolting Integrity Program manages the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Section XI related bolting and generic guidance regarding thread lubrication and assembly of bolted flanges. The program considers the guidelines delineated in NUREG-1339 for a bolting integrity program, EPRI NP-5769 (with the exceptions noted in NUREG-1339) for safety related bolting, and EPRI TR-104213 for non-safety related bolting. The Bolting Integrity Program credits seven separate aging management programs for the inspection of bolting.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 implies conformance with the recommendations of NUREG-1339, EPRI NP-5769, and EPRI TR-104213 concerning material selection and testing, preload control, inservice inspection, plant operation and maintenance, and evaluation of structural integrity. NUREG-1339 documents the resolution of Generic Safety Issue 29 related to bolting degradation or failure in nuclear power plants. NUREG-1339 relies on the industry technical findings presented in EPRI NP-5769 as the basis for resolution of the generic safety issue. EPRI NP-5769 is a broadly scoped document intended to resolve the generic safety issue and was formatted in a manner to aid the utility engineer in addressing bolting problems. EPRI TR-104213 was developed with the intention of providing a consolidated source of generic technical information pertaining to the design, assembly, inspection, trouble shooting, and repair of bolted joints. EPRI TR-104213 also includes recommendations for the selection, specification, and procurement of threaded fasteners. Due to the broad scope of these EPRI documents, the Bolting Integrity Program uses them as reference information and guidance only.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

The Bolting Integrity Program is primarily a condition monitoring program. The use of lubricants is in accordance with existing plant implementing documents, which reference the information and guidance in EPRI NP-5769 and EPRI TR-104213. Replacement of bolting in ASME Section XI components is performed in accordance with the plant's Repair and Replacement Program. Replacement of other bolting is like-for-like or evaluated on a case-by-case basis.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 states that initial Inservice Inspection (ISI) of pressure retaining bolting includes a check of bolt torque and uniformity of gasket compression. These parameters may be checked as part of the maintenance activity, but the initial ISI would only include an inspection for leakage of RCS components.

Enhancements to existing plant implementing documents dealing with bolted joints will be made to incorporate recommendations as deemed appropriate from the review of NUREG-1339, EPRI NP-5769, and EPRI TR-104213. As a minimum, these documents should be referenced for information and guidance.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The program monitors aging effects such as loss of material and loss of mechanical closure integrity. The specific parameters monitored or inspected are discussed in the seven credited programs and include inspection of pressure retaining bolted joints for signs of leakage and structural bolting for signs of degradation (e.g., corrosion). The high strength ($\geq$ 150 ksi yield) component support bolting at PBNP is used in pinned connections associated with the Steam Generator, Reactor Coolant Pump, and Reactor Vessel supports and is loaded only in shear. SCC of these bolts is not a concern because the bolts have no preload stress and are not located in an aggressive environment.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

Examination and testing of ASME Section XI, Class 1, 2, and 3 components are generally performed as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 (1998 Edition through 2000 Addenda), respectively. Information on component exemptions from examination requirements are given in the “PBNP Class 1, 2, and 3 Inservice Inspection Program” (Reference 35). The tables specify the extent of the examination, schedule, and methodology for components of pressure retaining boundaries. The program uses three types of examination: visual, surface, and volumetric. Visual VT-1 examination detects discontinuities and imperfections such as cracks, erosion, wear, and corrosion on the surface of components. Visual VT-2 examination detects evidence of leakage from pressure retaining components. Visual VT-3 examination: (a) determines the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacements; (b) detects discontinuities and imperfections such as loss of integrity at bolted connections, loose or missing parts, corrosion, wear, and erosion; and (c) observes conditions that could affect operability and functional adequacy of constant load and spring-type components and supports. Volumetric examinations may be used to detect the presence of discontinuities or flaws throughout the volume of selected components.

Structural bolting and fasteners are inspected by visual examinations. Components found defective are further inspected to assess the extent of degradation. The high strength (≥ 150 ksi yield) component support bolting at PBNP is used in pinned connections associated with the Steam Generator, Reactor Coolant Pump, and Reactor Vessel supports and is loaded only in shear. SCC of these bolts is not a concern because the bolts have no preload stress and are not located in an aggressive environment.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 states that degradation of structural bolting may be detected and measured either by removing the bolting, proof test by tension or torquing, by in situ ultrasonic tests, or hammer test. Components that are within scope of license renewal and are not within the scope of the ASME Section XI ISI programs are visually inspected for signs of degradation and are only inspected more closely when signs of degradation are present. PBNP does not plan to perform additional tests such as hammer tests, in situ ultrasonic tests, or proof tests by tension or torquing. The Bolting Integrity Program credits seven separate aging management programs. This exception only applies to the Structures Monitoring Program for this element. PBNP uses the 1998 Edition through 2000 Addenda of the ASME Section XI code instead of the 1995 Edition through 1996 Addenda referenced in NUREG-1801. The requirements of 1995 Edition through 1996 Addenda of ASME Section XI, Subsection IWB and IWC discussed in NUREG-1801 are encompassed by the requirements of the later code edition/addenda. Approved Relief Requests modify the code requirements relating to the inspection of bolted connections during system pressure tests and the corrective actions for identified leakage at bolted connections. A more detailed discussion of Relief Requests is included in the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

Enhancements include revisions to existing implementing documents to include specific inspections for the aging effects being managed by this program.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

Examination schedules contained in the PBNP ISI programs meet the requirements of ASME Section XI, Subsections IWB, IWC, IWD, and IWE for Class 1, 2, 3, and MC pressure retaining components. Examination schedules meet the requirements of ASME Section XI, Subsection IWF for Class 1, 2, and 3 supports.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 implies specific inspection intervals for leaking, non ASME Section XI pressure retaining bolted joints. The Bolting Integrity Program does not specify the inspection frequency for leaking joints, but instead relies on the plant maintenance and/or corrective action process to address the issue.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Acceptance Criteria

Indications or relevant conditions that are not removed are evaluated in accordance with IWB-3000, IWC-3000, IWD-3000, or IWE-3000 for Class 1, 2, 3, and MC components, respectively.

For Class 1, 2, and 3 piping supports, IWF-3410 identifies the following conditions as unacceptable: structural degradation of fasteners, clamps, or other support items; missing, detached, or loosened support items, and general corrosion on machined or sliding surfaces.

For the remaining components not covered above, indications of cracking in component support bolting, or leaks at bolted joints of pressure retaining components are evaluated and repaired if the degradation may cause a loss of intended function or cause adverse effects, such as corrosion or contamination.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 requires immediate repair of major leaks that cause corrosion or contamination. The Bolting Integrity Program makes no requirements for “immediate” repairs, but instead relies upon the plant maintenance and/or corrective action process to establish the appropriate priority and schedule repairs. This exception is considered acceptable based on plant-specific operating experience to date.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Bolting Integrity Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

A review of industry operating experience revealed numerous instances of primary pressure boundary degradation. There have been various NRC communications including information notices, bulletins, and generic letters on bolting degradation. Most instances of degradation fall into two categories: boric acid corrosion caused by leakage at mechanical joints; and degradation of high strength bolting caused by stress corrosion cracking. General corrosion of bolting and fasteners has also occurred for structural bolting located in a humid environment.

Plant specific operating experience includes boric acid wastage on one body/bonnet check valve stud. General corrosion was also found on structural steel bolting. There were also a few instances of improper bolting material and torque values being used. There were no incidents of loss of intended function of a component or system due to fastener degradation.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Bolting Integrity Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

Seven aging management programs are credited by the Bolting Integrity Program to cover the inspection of all the bolting within the scope of license renewal at PBNP. Collectively, the credited programs demonstrate that the Bolting Integrity Program provides reasonable assurance that the aging effects of concern will be managed, such that SSCs within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation and that observed degradation will result in repair or replacement before a loss of the intended function.

B2.1.5 Boraflex Monitoring Program

Program Description

The Boraflex Monitoring Program manages aging effects for the Boraflex material in the spent fuel racks. This program provides for blackness testing and areal density measurements of the Boraflex material in the spent fuel storage racks to confirm the in-service Boraflex performance. In addition, tracking of the spent fuel pool silica levels provides a qualitative indication of boron carbide loss. The results of silica sampling will be trended and analyzed using a predictive code. Neutron attenuation or blackness testing will be performed to determine gap formation, while areal density measurements will be used to ascertain the physical loss of boron carbide. Monitoring and analysis of criticality will also be performed to assure that the required 5% sub criticality margin is maintained. Based on the results of these inspections and analysis, appropriate measures will be taken to ensure the Boraflex will continue to perform its intended function. This program addresses the concerns described in NRC GL 96-04.

A reduction of neutron absorption capabilities due to a change in material properties could impact the ability of Boraflex to perform its intended function. When Boraflex is subjected to gamma radiation, shrinkage and the potential to develop tears or gaps in the material can occur. The radiation exposure alters the chemical properties of the polymer matrix by weakening the chemical bonds. As a result of being in a convective aqueous environment in the spent fuel pool (SFP), the silicon polymer matrix becomes degraded and silica filler and boron carbide are released.

The Boraflex Monitoring Program uses Boraflex areal density measurements and blackness testing to measure Boraflex deterioration. These two test methodologies provide performance data for the Boraflex panels in the spent fuel pool in terms of gap formation, gap distribution and gap size (i.e., blackness testing), and in terms of grams of Boron-10 atoms per unit area in square centimeters (i.e., Boraflex areal density). The test results from the areal density measurements and the blackness testing are used to evaluate the Boraflex integrity in the spent fuel racks of the spent fuel pool.

The frequency for areal density testing and blackness testing is once every five years. The surveillance examines a minimum of 10 full length Boraflex panels selected from those that have been exposed to the greatest number of freshly discharged fuel assemblies. The 10 panels include 4 panels with accelerated exposure and 6 panels selected at random. The results of the Boraflex areal density test results are evaluated as part of the Boraflex Monitoring Program to determine if a change in test frequency or methodology is warranted.

The Boraflex panels that have been exposed to the greatest number of freshly discharged fuel assemblies are determined by employing two different methods. Through the use of fuel assembly records and a spreadsheet, a list of those cells that have the highest exposure is compiled. The EPRI RACKLIFE predictive code or it's equivalent is also used to determine which cells have seen the greatest dose. The SFP tracking database is used to track spent fuel assembly locations and is used to track the neutron flux delivered to the Boraflex neutron-absorbing panels in the SFP. The panels that are examined by blackness testing and areal density testing have been exposed to the highest gamma flux for the longest period of time or the greatest accumulated dose.

The Boraflex Monitoring Program trends and analyzes the results of the silica sampling by using the EPRI RACKLIFE predictive code or its equivalent on a monthly, quarterly or an annual basis depending on the condition of the Boraflex panels.

The test results of the areal density testing are used in conjunction with the trending of SFP silica levels to verify that the design basis of the spent fuel racks is maintained or alternatively to ensure that corrective actions are initiated.

NUREG-1801 Consistency

The Boraflex Monitoring Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M22 “Boraflex Monitoring” (Reference 3).

Exceptions to NUREG-1801

See the following element discussion for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Detection of Aging Effects

Enhancements

Enhancements to the Boraflex Monitoring Program include: creation of a new procedure to perform and control Boraflex areal density and blackness testing, creation of a new procedure for trending and analysis of the results of the Spent Fuel Pool silica sampling by using the EPRI RACKLIFE predictive code or its equivalent, and determination of panels with “accelerated” exposure during the period of extended operation. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Boraflex Monitoring Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M22, “Boraflex Monitoring,” is also provided below.

Scope of Program

The Boraflex Monitoring Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Primary Auxiliary Building Structure

The Boraflex Monitoring Program is credited with managing the aging effect of a reduction of neutron absorption capabilities due to a change in material properties (i.e., shrinkage, gap formation, and boron dissolution) resulting from gamma irradiation and a convective aqueous environment for the Boraflex material in the spent fuel racks. For Boraflex panels, gamma irradiation and long-term exposure to the wet pool environment cause shrinkage resulting in gap formation, gradual degradation of the polymer matrix, and the release of silica to the spent fuel storage pool water. This results in the loss of boron carbide in the neutron absorber sheets. This program provides for blackness testing and areal density measurements of the Boraflex material in the spent fuel storage racks. These inspections will confirm the in-service Boraflex performance data in terms of gap formation, gap distribution, and gap size. In addition, tracking of the spent fuel pool silica levels provides a qualitative indication of boron carbide loss. Areal density measurements will be used to ascertain the physical loss of boron carbide. Based on the results of these inspections and analysis, appropriate measures will be taken to ensure the Boraflex will continue to perform its intended function.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

The Boraflex Monitoring Program is based on condition monitoring. For the Boraflex panels in spent fuel racks, monitoring silica levels in the spent fuel pool water, measuring Boraflex gap formation by blackness testing, periodically measuring boron areal density, and applying predictive codes are performed. These actions ensure that degradation of the neutron-absorbing material is identified and corrected so the spent fuel storage racks will be capable of performing their intended functions during the period of extended operation, consistent with current licensing basis (CLB) design conditions.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in NRC Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25% silica, 25% polydimethyl siloxane polymer, and 50% boron carbide, sampling and analysis of the presence of silica in the spent fuel pool provides an indication of depletion of boron carbide from Boraflex; however, the degree to which Boraflex has degraded is ascertained through measurement of the boron areal density.

The Boraflex Monitoring Program determines the amount of degradation of the Boraflex material. The program, which includes blackness testing, confirms the in-service Boraflex panel performance data in terms of gap formation, gap distribution and gap size. In addition, sampling and trending of the SFP silica concentrations provides a qualitative indication of boron carbide loss from the Boraflex panels. The presence of silica in the SFP water is a physical sign of the aging effect of the Boraflex material. Silica level in the spent fuel pool is monitored monthly by plant procedures. The Boraflex Monitoring Program also includes checking the areal density of the Boraflex to measure the physical loss of boron carbide from the neutron-absorbing material.

A new procedure will be created for trending and analysis of the results of the Spent Fuel Pool silica sampling by using the EPRI RACKLIFE predictive code or its equivalent, and determination of panels with “accelerated” exposure during the period of extended operation. The results of this trending and analysis will be evaluated to determine if a change in Boraflex areal density test frequency or methodology is warranted.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

The Boraflex Monitoring Program detects aging effects on the Boraflex panels through blackness testing and by trending the silica levels in the water of the spent fuel pool. The blackness testing detects aging effects in terms of gap formation, gap distribution and gap size. The presence of silica in the SFP water is a physical sign of the aging effect of the Boraflex material. Silica level in the spent fuel pool is monitored monthly by plant procedures.

The Boraflex Monitoring Program trends and analyzes the results of the silica sampling by using the EPRI RACKLIFE predictive code or its equivalent on a monthly, quarterly, or annual basis depending on Boraflex panel condition. The program determines the amount of boron carbide released from the Boraflex panels in the spent fuel pool, by direct measurement of boron areal density and subsequent correlation with the levels of silica present through the use of a predictive code. This is supplemented with detection of gaps through blackness testing. The current frequency of analyzing the SFP water for silica concentration is monthly. The Boraflex areal density testing and the blackness testing of the Boraflex panels will take place at a minimum frequency of once every five years under the Boraflex Monitoring Program. A new procedure to perform and control Boraflex areal density and blackness testing will be created.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The NUREG-1801 program description states that “Certain accelerated samples are tested every two years.” The Boraflex Monitoring Program performs these tests at a minimum frequency of five years. Two SFP storage locations had received freshly discharged spent fuel assemblies each refueling for approximately 9 years, which has caused accelerated cumulative exposure levels to the bordering Boraflex panels. Four of these panels are tested during each scheduled surveillance. The results of the Boraflex areal density testing and Boraflex panel blackness testing are evaluated as part of the Boraflex Monitoring Program to determine if a change in test frequency or methodology is warranted. Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

Silica level in the SFP is monitored monthly by plant procedures. The Boraflex Monitoring Program trends and analyzes the results of the silica sampling by using the EPRI RACKLIFE predictive code or its equivalent on a monthly, quarterly, or annual basis depending on Boraflex panel condition.

Monitoring for shrinkage and gaps, and testing of the Boraflex areal density takes place during scheduled Boraflex surveillances, which are performed at a minimum frequency of five years.

The results of the Boraflex areal density testing and Boraflex panel blackness testing are evaluated as part of the Boraflex Monitoring Program to determine if a change in test frequency or methodology is warranted. The program determines the amount of boron carbide released from the Boraflex panels in the spent fuel pool, by direct measurement of boron areal density and subsequent correlation with the levels of silica present through the use of a predictive code.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

The results of the areal density testing will be trended, since this method is capable of determining the material thickness. The Boraflex Monitoring Program determines the amount of boron carbide released from the Boraflex panels in the spent fuel pool, by direct measurement of boron areal density and subsequent correlation with the levels of silica present through the use of a predictive code. Analysis of these trends are used to predict when the 5% subcriticality margin of the spent fuel racks in the SFP will no longer be maintained. Corrective actions will be taken to ensure that the 5% subcriticality margin of the spent fuel racks is maintained for the period of extended operation.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Boraflex Monitoring Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

NRC Information Notice IN 87-43 (Reference 14) addresses the problems of development of tears and gaps in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC IN 93-70 (Reference 15), NRC IN 95-38 (Reference 16) and NRC GL 96-04 (Reference 13) address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by spent fuel pool water flow through panel enclosures and high accumulated gamma dose. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, boraflex integrity is measured and correlated, through a predictive code, with the silica levels in the pool water during the period of extended operation. These actions provide reasonable assurance that degradation of Boraflex sheets is adequately monitored, so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. This monitoring ensures that the Boraflex sheets will maintain their integrity and will be effective in performing their intended function.

Silica concentrations in the SFP are monitored and trended. There has been a slow but steady increase in the concentration of silica in the SFP. In 1996, PBNP wrote that … “The silica levels in the spent fuel pool have been increasing and the rate of increase has been slightly accelerating. Silica dissolution is a direct result of irradiation and the slight acceleration in pool silica levels is attributed to the greater quantity of spent fuel assemblies in the pool, not to an increase in the per-panel Boraflex degradation rate” (Reference 36).

Blackness testing (neutron attenuation measurements) has been performed on a test frequency of once every five years on specific Boraflex panels in the spent fuel pool. The first three rounds of Boraflex panel blackness testing were completed in August 1991, September 1996 and August 2001. The program uses blackness testing to examine full-length Boraflex panels selected from those that have been exposed to the greatest number of freshly discharged fuel assemblies. Engineering evaluations are then performed to evaluate the results of the blackness testing and to confirm the subcriticality margin.

The latest inspection of the SFP Boraflex panels was conducted in August 2001. The results of the Blackness Test indicated that for the first time since the Boraflex panels have been inspected, gaps have been found in 27 panels ranging from 0.8 inches to 3.4 inches. The gaps appear to be randomly distributed along the vertical length of the Boraflex panels. A Condition Report was issued to monitor the condition of the Boraflex in the SFP.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Boraflex Monitoring Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Boraflex Monitoring Program provides reasonable assurance that the intended function of the Boraflex panels will be maintained consistent with the current licensing basis during the period of extended operation. Shrinkage and gap formation of the

Boraflex within the stainless steel encasements of the panels are the aging effects most likely to impact the intended function of the Wachter designed Boraflex panels. Boraflex blackness testing and areal density testing techniques are used for detecting Boraflex shrinkage and gap formation and determining the boron carbide density. Areal density testing when used in conjunction with SFP silica monitoring has already been successfully used by several nuclear facilities and the Electric Power Research Institute. (EPRI).

B2.1.6 Boric Acid Corrosion Program

Program Description

The Boric Acid Corrosion Program manages aging effects for structures and components as a result of borated water leakage. The program requires periodic visual inspection of systems that contain borated water for evidence of leakage or accumulations of dried boric acid. It includes provisions for (a) determination of the principal location or source of the leakage, (b) examination requirements and procedures for locating small leaks, and (c) evaluations and/or corrective actions to ensure that boric acid leakage does not lead to degradation of the leakage source as well as other SSC exposed to the leakage, including mechanical, structural, and electrical items such as bolts, fasteners, piping, cables, cable trays, electrical connectors, etc., which could cause the loss of intended function(s). This program complies with PBNP's response to NRC GL 88-05.

Material loss or other component degradation due to boric acid can impact the ability of SSC to perform their intended function(s) if permitted to continue without corrective action. As a result, various plant systems containing borated water were identified to be within the scope of this program.

This program credits the Systems Monitoring Program for the visual inspection of other SSC that do not contain borated water, but may be subject to the degrading effects of any borated water leakage.

As part of the Boric Acid Corrosion Program, PBNP monitors operating experience relating to boric acid leaks and takes appropriate corrective actions. Thus by conducting visual inspections, locating the source of the leaks when they are discovered, performing evaluations, and reviewing internal and external operating experience, the program assures that the systems and components containing borated water will continue to perform their intended functions. The program also provides for visual inspections and early discovery of borated water leaks such that structures or components that may be contacted by leaking borated water will not be affected by the leaks and that their intended function(s) will not be impaired.

When small boric acid leaks are discovered, they are either evaluated as being acceptable or corrected through the corrective maintenance process. Significant leaks or primary pressure boundary degradation will trigger documentation through the corrective action program.

NUREG-1801 Consistency

The Boric Acid Corrosion Program is an existing program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M10, “Boric Acid Corrosion.” (Reference 3).

Exceptions to NUREG-1801

None

Enhancements

Enhancements to the Boric Acid Corrosion Program include: revisions to existing procedures to more clearly state that susceptible components upon which borated water may have leaked are inspected for degradation, and the development of new implementing document(s) that will be applicable to systems and components not presently covered by existing procedures. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Boric Acid Corrosion Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M10, “Boric Acid Corrosion,” is also provided below.

Scope of Program

The Boric Acid Corrosion Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

4160 VAC Power	Main and Auxiliary Steam
480 VAC Power	Miscellaneous AC Power and Lighting
Auxiliary Feedwater	Non-Class 1 RCS Components
Chemical and Volume Control	Plant Air

Class 1 Piping/Components	Plant Communications
Component Cooling Water	Primary Auxiliary Building Structure
Component Supports Commodity Group	Pressurizer
Containment Hydrogen Detectors and Recombiners	Radiation Monitoring
Containment Isolation Components	Reactor Vessel
Containment Spray	Residual Heat Removal
Containment Unit 1/2 Building Structure	Safety Injection
Containment Ventilation	Service Water
Control Rod Drive and Indication and Nuclear Process Instrumentation	Spent Fuel Cooling
Feedwater and Condensate	Steam Generator
Fire Protection	Treated Water
Heating Steam	Waste Disposal

The Boric Acid Corrosion Program includes any carbon steel, low alloy steel, or cast iron structures or components, and electrical components, on which borated water may leak. The program adheres to NRC Generic Letter 88-05. It includes (a) determination of the leakage source, (b) examination requirements and procedures for locating small leaks, and (c) evaluations and/or corrective actions. This will ensure that boric acid corrosion does not lead to degradation of the leakage source or adjacent structures or components, which could cause the loss of intended function of the structures or components.

In addition to the inspections performed during pressure testing, pre-outage walkdowns of systems that contain boric acid are performed to identify those components that may require corrective maintenance and to correct adverse boric acid leakage. These walkdowns are also performed to minimize the probability of abnormal leakage, rapidly propagating failures, or gross rupture.

Enhancements to existing procedures will be made to more clearly state that susceptible components, upon which borated water may have leaked, are inspected for degradation, including mechanical, structural, and electrical items such as bolts, fasteners, piping, cables, cable trays, electrical connectors, etc. Additional implementing documents will be prepared as needed to address systems and components not presently covered by existing procedures.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

Preventive actions are limited to improving maintenance practices such as revising the valve packing program to improve packing techniques, performance of pre-outage walkdowns to identify those components that may require corrective maintenance, and monitoring of locations where potential leakage could occur. Timely repair of detected leakage prevents or mitigates boric acid corrosion.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

Visual inspections are conducted to monitor the effects of boric acid corrosion on the intended function(s) of an affected structure or component. Borated water leakage results in deposit of white boric acid crystals and presence of moisture that can be observed by visual inspections during system walkdowns.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

Degradation of components due to boric acid corrosion cannot occur without borated water leakage. Visual inspections are frequently conducted (e.g., pre-outage, at the beginning of an outage) to identify necessary repairs and minimize the potential of a leak not being discovered and developing into a larger leak. Guidelines for detecting small leaks by visual inspections are utilized and evaluations are conducted when leaks are detected. Post maintenance inspections are conducted to verify that repairs were properly performed. Therefore, the Boric Acid Corrosion Program, which follows the guidelines of NRC GL 88-05, will assure the detection of leakage before a loss of an intended function(s).

This program also credits the Systems Monitoring Program for the visual inspection of other SSC that do not contain borated water, but may be subject to the degrading effects of any borated water leakage.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

The program relies on visual inspections conducted during normal plant operation and when the plant is shutdown for refueling. The program follows the guidelines in NRC GL 88-05 and provides for timely detection of leakage by observance of boric acid crystal deposits during plant walkdowns and maintenance.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

Plant procedures provide recording criteria if any leakage of boric acid is noted, and evaluation guidance and acceptance criteria for any recorded indications of boric acid leakage.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Boric Acid Corrosion Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

Industry operating experience clearly indicates that a boric acid solution leaking from the Reactor Coolant System can cause significant corrosion damage to carbon steel reactor coolant pressure boundary components. Severe corrosion damage to the RPV head at Davis-Besse and observed cracking and leakage on the RPV bottom head penetrations at South Texas have resulted in much industry attention to ensuring the implementation of an effective boric acid corrosion program. The PBNP Boric Acid Corrosion Program is enhanced by continued involvement with industry initiatives and operating experience.

A review of plant operating experience indicates that numerous Work Orders, Condition Reports/Action Requests, and several Licensee Event Reports have been issued as a result of the Boric Acid Corrosion Program discovering boric acid leaks and corrosion of components due to borated water leakage. A large percentage of the Work Orders and Condition Reports/Action Requests initiated described finding dried boric acid crystal deposits either on the component from which it leaked or on the floor below the leaking component. Occasionally, dried boric acid crystals were found on components located below the leaking component. Many of the Work Orders initiated to repair and/or investigate evidence of borated water leakage were a result of performing system walkdowns during pressure testing.

NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 were reviewed. Several enhancements were made to the PBNP GL 88-05 boric acid control program as a result of an Action Request initiated by the Nuclear Oversight Group. These enhancements included consolidation of the program requirements into one document, assignment of program ownership, and the addition of program references to various implementing documents. Completion of these enhancements was tracked via the corrective action program. No other issues or findings that could impact the effectiveness of the Boric Acid Corrosion Program were identified. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Boric Acid Corrosion Program provides reasonable assurance that the associated aging effects will be managed such that SSC within the scope of license renewal will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation. Industry and plant-specific operating experience has shown that timely discovery and evaluation of borated water leakage provides reasonable assurance that boric acid corrosion will not compromise intended function(s). Early detection of borated water leakage is provided at PBNP by visual inspections. These inspections take into consideration other indications of borated water leakage such as monitoring for radioactive particulate and gas, containment humidity and sump drainage, and RCS inventory balances. Evaluations and corrective actions address the source of the leakage and structures and components exposed to the leakage. PBNP's response to NRC Bulletin 2002-01 included a description and evaluation of the plant's boric acid inspection program. The response concluded that the program is in compliance with the regulatory requirements of Generic Letter 88-05.

B2.1.7 Buried Services Monitoring Program

Program Description

The Buried Services Monitoring Program manages aging effects on the external surfaces of carbon steel, low-alloy steel, and cast iron components (e.g., tanks, piping) that are buried in soil or sand. This program includes (a) preventive measures to mitigate degradation (e.g., external coatings and wrappings), and (b) visual inspections of external surfaces of buried components for evidence of coating damage and substrate degradation to manage the effects of aging. The periodicity of these inspections will be based on plant operating experience and opportunities for inspection such as scheduled maintenance work.

The Buried Services Monitoring Program assures that the effects of aging on buried piping, tanks, and miscellaneous components are being effectively managed for the period of extended operation. The effects of corrosion are detectable by visual inspections, while the effects of selective leaching are detectable by visual inspections and/or hardness measurements.

This is a new program for PBNP that includes preventive measures such as coatings and wrappings to mitigate loss of material due to corrosion and selective leaching, and visual inspections of the external surfaces of buried carbon steel, cast iron, and low alloy steel components (e.g., piping, tanks) for evidence of coating damage and substrate degradation. Evidence of damage to the coating or wrapping, such as coating perforation, holidays, or other damage will cause the protected components to be inspected for evidence of loss of material.

NUREG-1801 Consistency

The Buried Services Monitoring Program is a new program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M34, “Buried Piping and Tank Inspection” (Reference 3).

Exceptions to NUREG-1801

None

Enhancements

The Buried Services Monitoring Program is a new program at PBNP. Enhancements to the program include the creation of those documents needed to implement the requirements of the program to manage the aging effects of concern for those systems and components within the scope of license renewal that credit the program. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Buried Services Monitoring Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M34, “Buried Piping and Tank Inspection,” is also provided below.

Scope of Program

The Buried Services Monitoring Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Emergency Power	Service Water
Fire Protection	

The program includes preventive measures to mitigate degradation (e.g., external coatings and wrappings) and visual inspections of the external surfaces of buried carbon steel, cast iron, and low alloy steel components (e.g., piping, tanks) for evidence of coating damage and substrate degradation. Inspections will be performed based on plant operating experience and opportunities for inspection such as scheduled maintenance.

Enhancements to the Buried Services Monitoring Program will result in the creation of procedures to implement the program requirements.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

Buried components (e.g., piping, tanks) are coated per industry practice prior to installation in order to protect the component outer surfaces from corrosion and selective leaching.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The program monitors parameters such as coating and wrapping integrity that are directly related to loss of material due to corrosion and selective leaching on the external surfaces of buried carbon steel, low alloy steel, and cast iron components. Coatings and wrappings are visually inspected. Evidence of damage to the coating or wrapping, such as coating perforation, holidays, or other damage will cause the protected components to be inspected for evidence of loss of material. The effects of corrosion are detectable by visual inspections, while the effects of selective leaching are detectable by visual inspections and/or hardness measurements.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

Inspections of buried components (e.g., piping and tanks) at susceptible locations are performed to confirm that coatings and wrappings are intact to ensure that age-related degradation of external surfaces has not occurred and that the intended function of the components is maintained. The periodicity of these inspections will be based on plant operating experience and opportunities for inspection such as scheduled maintenance work.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

Inspection results will be evaluated, and used to assess the condition of the external surfaces of buried components and to identify susceptible locations that may warrant further inspections.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

Evidence of coating and wrapping degradations will be documented and evaluated under the corrective action program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Buried Services Monitoring Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

This is a new program for PBNP which is being initiated for license renewal. Industry operating experience has shown that carbon steel, low alloy steel, or cast iron buried components have experienced corrosion and selective leaching degradation. The critical areas appear to be at the interface where the component transitions from above ground to below ground. This is also the area where coatings and wrappings will most likely be missing or damaged.

A Condition Report was initiated in 1993 at PBNP when the coating on a 30 inch service water pipe and a 1 inch fuel oil line was damaged during excavation for the diesel generator project duct bank and fuel oil line installation. The condition report noted that the coatings were repaired and stated “No corrosion of existing piping was noted during the repair.”

A repair to a post-indicating valve was performed in June of 2002. This repair required the ground to be excavated, which exposed buried portions of the valve and Fire Protection System piping. The outside surface of the piping showed no signs of corrosion after being buried for almost 14 years.

The Service Water, Fuel Oil, and Fire Water Systems have buried pipe, which has been in service for over 30 years. Leakage due to external corrosion of buried portions of these systems has not been a problem at PBNP. The protective coatings and relatively non-aggressive soil conditions serve to lessen the probability of component degradation due to corrosion.

Based on this plant-specific operating experience, the implementation of the Buried Services Monitoring Program will adequately manage the aging effect loss of material due to corrosion and selective leaching for the period of extended operation. As additional operating experience is obtained, lessons learned may be used to adjust this program.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Buried Services Inspection Program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

Implementation of the Buried Services Monitoring Program provides reasonable assurance that the aging effect loss of material due to corrosion and selective leaching will be managed such that systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. This is a new program for PBNP that has been initiated for the purpose of license renewal. Inspections will be performed based on plant operating experience and opportunities for inspection such as scheduled maintenance. The results of the visual inspections will be reviewed and evaluated to identify susceptible locations that may warrant further inspections.

B2.1.8 Cable Condition Monitoring Program

Program Description

The Cable Condition Monitoring Program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The scope of this program includes accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal. The program requires (a) visual inspection of a representative sample of accessible electrical cables and connections in adverse localized environments once every 10 years for evidence of jacket surface degradation, (b) testing of nuclear instrumentation circuits once every 10 years to detect a significant reduction in cable insulation resistance, and (c) testing of a representative sample of in-scope, medium-voltage cables not designed for submergence subject to prolonged exposure to significant moisture and significant voltage once every 10 years to detect deterioration of insulation.

The Cable Condition Monitoring Program provides reasonable assurance that the intended functions of electrical cables and connections within the scope of license renewal that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat, radiation, or moisture are maintained consistent with the current licensing basis through the period of extended operation. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Standard P1205-2000, SAND96-0344, and EPRI TR-109619.

This program addresses cables and connections whose configuration is such that most cables and connections installed in adverse localized environments are accessible. It is a sampling program where selected cables and connections from accessible areas are inspected and represent, with reasonable assurance, all cables and connections in adverse localized environments. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination would be made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections.

Nuclear instrumentation circuits are periodically tested to provide an indication of the condition of the cable insulation. The specific type of test performed is determined prior to testing and capable of detecting a significant reduction in cable insulation resistance. If an unacceptable condition or situation is identified, a determination would be made as to whether the same condition or situation is applicable to other cables used in nuclear instrumentation circuits.

Periodic actions are taken to prevent cables not designed for submergence from being subject to prolonged exposure to significant moisture, such as inspecting for water collection in cable manholes and draining water, as needed. A representative sample of inaccessible medium-voltage cables not designed for submergence within the scope of license renewal subject to prolonged exposure to significant moisture and significant voltage are periodically tested to provide an indication of the condition of the conductor insulation. The specific type of test performed is determined prior to testing and capable of detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2 (Reference 40). If an unacceptable condition or situation is identified for an inaccessible medium-voltage cable subject to prolonged exposure to significant moisture and significant voltage in the test sample, a determination would be made as to whether the same condition or situation is applicable to other inaccessible medium-voltage cables.

NUREG-1801 Consistency

The Cable Condition Monitoring Program is a new program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” and consistent with, but includes exceptions to, XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” and XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 program element assumptions:

- Scope of Program
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Acceptance Criteria

Enhancements

Enhancements to the Cable Condition Monitoring Program include establishing a new program that manages aging of conductor insulation materials on cables and connections, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The scope of this program includes accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal. These enhancements are required to satisfy NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Cable Condition Monitoring Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” and XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” is also provided below.

Scope of Program

The Cable Condition Monitoring Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

120 VAC Vital Instrument Buses	Engineered Safety Features Actuation
125 VDC Power	Miscellaneous AC Power and Lighting
13.8K VAC Power	Offsite Power
4160 VAC Power	Plant Communications
480 VAC Power	Radiation Monitoring
Control Rod Drive and Indication and Nuclear Process Instrumentation	Reactor Protection

The scope of this program includes accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal.

- Accessible Non-EQ Electrical Cables and Connections

  This program applies to accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, within the scope of license renewal that are installed in adverse localized environments caused by heat, radiation, or moisture in the presence of oxygen.

PBNP has not identified any fuse holders outside the enclosure of an active component that require aging management. However, should such fuse holders be identified in the future, they would be appropriately managed within the Cable Condition Monitoring Program to address the concerns identified in ISG-5.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

- Non-EQ Electrical Cables Used in Nuclear Instrumentation Circuits

This program applies to non-EQ electrical cables used in nuclear instrumentation circuits with sensitive, high voltage, low-level signals that are within the scope of license renewal and are installed in adverse localized environments caused by heat or radiation in the presence of oxygen.

This element includes exceptions to NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.” The Cable Condition Monitoring Program only includes non-EQ electrical cables used in nuclear instrumentation circuits that are within the scope of license renewal and are installed in adverse localized environments, while the NUREG-1801 program applies to all non-EQ instrumentation circuits with sensitive, high voltage, low-level signals exposed to adverse localized environments such as radiation monitoring and nuclear instrumentation that are within the scope of license renewal. Operating experience has shown that visual inspections of non-EQ instrumentation circuit cables within the scope of license renewal are adequate to identify aging degradation, as documented in SAND96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations.” Electrical cables associated with radiation monitoring instrumentation within the scope of license renewal at PBNP are either environmentally qualified in accordance with 10 CFR 50.49 or not installed in adverse localized environments (e.g., radiation monitoring instrumentation associated with the Control Room).

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

- Inaccessible Non-EQ Medium-Voltage Cables

  This program applies to inaccessible (e.g., in conduit or direct buried) non-EQ medium-voltage cables not designed for submergence within the scope of license renewal that are subject to prolonged exposure to significant moisture simultaneously with significant voltage. Prolonged exposure to significant moisture is defined as exposures to significant moisture that last more than a few years (e.g., cable in standing water). Periodic exposures to moisture such as normal rain and drain or seasonal ground water level rise and decline are not prolonged. Significant moisture is defined as fully wetted and submerged, such as in standing water. Periodic wetting, such as condensation, water spray, or occasional water flow over a cable are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. The moisture and voltage exposures described as significant in these definitions, which are based on operating experience and engineering judgment, are not significant for medium-voltage cables designed for these conditions (e.g., continuous wetting and continuous energization is not significant for marine cables).

  This element includes exceptions to NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.” The NUREG-1801 program defines significant moisture as periodic exposures to moisture that last more than a few days. The Cable Condition Monitoring Program is based on prolonged exposure to significant moisture, which is defined as exposures to significant moisture that last more than a few years. This definition is acceptable for the following reasons.

  Medium-voltage cables at PBNP were ordered moisture resistant for direct buried or underground service, but are not used in direct buried applications. Medium-voltage cables used at PBNP are installed in conduit, duct packs/banks, or manholes, which provide a flow path to drain water (e.g., duct packs/banks are sloped).

  The formation and growth of water trees varies directly with operating voltage. As stated in NUREG-1801, treeing is much less prevalent in 4K VAC cables than those operated at 13 or 33K VAC. Major portions of the higher medium-voltage (13.8K VAC) cables used at PBNP, which are more susceptible to water treeing, were replaced in 1988 with cables ordered moisture resistant for direct buried or underground service. In addition, the 13.8 K VAC cables subject to submergence were successfully tested in 2003 using the Energized Partial Discharge Testing Methodology.

XLPE or high molecular weight polyethylene (HMWPE) insulation materials are most susceptible to water tree formation. Based on a review of cable data, PBNP has no cables with XLPE insulation being operated in the medium-voltage range (i.e., 2K VAC to 15K VAC).

Minimizing exposure to moisture also minimizes the potential for the development of water treeing. Manhole flooding and groundwater intrusion has been a long standing issue at PBNP and efforts were periodically taken to reduce the exposure of medium-voltage cables to water. In order to better understand the magnitude of the groundwater intrusion problem into the electrical manholes, a new call-up to inspect and pump the flooded manholes was initiated. The new call-up periodically inspects and pumps down the electrical manholes, as necessary. As part of the new call-up, the approximate water level in each manhole is recorded. The recording of the water level will provide the basis for any future changes in frequency to the call-up and any deletion of manhole inspections.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Enhancements to the Cable Condition Monitoring Program include establishing a new program that manages aging of conductor insulation materials on cables and connections, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture.

Preventive Actions

- Accessible Non-EQ Electrical Cables and Connections

  This is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation.

  This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

- Non-EQ Electrical Cables Used in Nuclear Instrumentation Circuits

  This is a testing program and no actions are taken as part of this program to prevent or mitigate aging degradation.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.”

- Inaccessible Non-EQ Medium-Voltage Cables

  Periodic actions are taken to prevent medium-voltage cables not designed for submergence from being subject to prolonged exposure to significant moisture, such as inspecting for water collection in cable manholes and draining water, as needed. Medium-voltage cables for which such actions are taken are not required to be tested since operating experience indicates that prolonged exposure to significant moisture simultaneously with significant voltage are required to induce the aging effects of concern.

  This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Parameters Monitored or Inspected

- Accessible Non-EQ Electrical Cables and Connections

  A representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies, such as discoloration, swelling, cracking, or surface contamination. This sample is based on the severity of the adverse localized environment, as compared to the plant design environment, and other criteria such as accessibility, availability, importance-to-safety, and/or prior inspection results.

  This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

- Non-EQ Electrical Cables Used in Nuclear Instrumentation Circuits

  Nuclear instrumentation circuits are periodically tested to provide an indication of the condition of the cable insulation. The specific type of test performed is determined prior to testing and capable of detecting a significant reduction in cable insulation resistance. A significant reduction in insulation resistance is defined as a reduction in insulation resistance that adversely affects the accuracy of nuclear instrumentation circuits.

This element includes exceptions to NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.” The NUREG-1801 program indicates that the parameters monitored are specified in the plant technical specifications. However, the surveillance tests required by the PBNP technical specifications do not include the electrical cables for certain nuclear instrumentation circuits. Therefore, the Cable Condition Monitoring Program periodically tests nuclear instrumentation circuits to provide an indication of the cable insulation condition, which meets the intent of this NUREG-1801 aging management program element.

- Inaccessible Non-EQ Medium-Voltage Cables

A representative sample of in-scope, inaccessible medium-voltage cables not designed for submergence subject to prolonged exposure to significant moisture and significant voltage are periodically tested to provide an indication of the condition of the conductor insulation. This sample is based on the severity of prolonged exposure to significant moisture and significant voltage, and the age of the cable. The specific type of test performed is determined prior to testing and capable of detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2.

This element includes exceptions to NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.” The Cable Condition Monitoring Program requires periodic testing of a representative sample of in-scope, inaccessible medium-voltage cables not designed for submergence subject to prolonged exposure to significant moisture and significant voltage, while the NUREG-1801 program implies all such cables are to be tested. This sampling approach is acceptable for the following reasons.

Medium-voltage cables at PBNP were ordered moisture resistant for direct buried or underground service, but are not used in direct buried applications. Medium-voltage cables used at PBNP are installed in conduit, duct packs/banks, or manholes, which provide a flow path to drain water (e.g., duct packs/banks are sloped).

The formation and growth of water trees varies directly with operating voltage. As stated in NUREG-1801, treeing is much less prevalent in 4K VAC cables than those operated at 13 or 33K VAC. Major portions of the higher medium-voltage (13.8K VAC) cables used at PBNP, which are more susceptible to water treeing, were replaced in 1988 with cables ordered moisture resistant for direct buried or underground service. In addition, the 13.8 K VAC cables subject to submergence were successfully tested in 2003 using the Energized Partial Discharge Testing Methodology.

XLPE or high molecular weight polyethylene (HMWPE) insulation materials are most susceptible to water tree formation. Based on a review of cable data, PBNP has no cables with XLPE insulation being operated in the medium-voltage range (i.e., 2K VAC to 15K VAC).

Minimizing exposure to moisture also minimizes the potential for the development of water treeing. Manhole flooding and groundwater intrusion has been a long standing issue at PBNP and efforts were periodically taken to reduce the exposure of medium-voltage cables to water. In order to better understand the magnitude of the groundwater intrusion problem into the electrical manholes, a new call-up to inspect and pump the flooded manholes was initiated. The new call-up periodically inspects and pumps down the electrical manholes, as necessary. As part of the new call-up, the approximate water level in each manhole is recorded. The recording of the water level will provide the basis for any future changes in frequency to the call-up and any deletion of manhole inspections.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Detection of Aging Effects

- Accessible Non-EQ Electrical Cables and Connections

Conductor insulation aging degradation from heat, radiation, or moisture in the presence of oxygen causes cable and connection jacket surface anomalies. A representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected once every 10 years. As stated in NUREG-1801, this is an adequate inspection period to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. The first inspection for license renewal is to be completed before the period of extended operation.

A representative sample of accessible cables and connections are visually inspected for surface abnormalities, such as discoloration, swelling, cracking or surface contamination. Surface abnormalities are a precursor indication of insulation degradation. Guidelines provided in EPRI TR-109619 (Reference 21) may be used as an aid in the identification of undesirable conditions. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination would be made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

- Non-EQ Electrical Cables Used in Nuclear Instrumentation Circuits

Cables used in nuclear instrumentation circuits are tested once every 10 years to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function. This is an adequate period to identify cable degradation to preclude excessive leakage currents since experience has shown that aging degradation is a slow process. The first tests for license renewal are to be completed before the period of extended operation. If an unacceptable condition or situation is identified, a determination would be made as to whether the same condition or situation is applicable to other cables used in nuclear instrumentation circuits.

This element includes exceptions to NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.” The NUREG-1801 program indicates that the normal calibration frequency specified in the plant technical specifications is acceptable. However, the surveillance tests required by the PBNP technical specifications do not include the electrical cables for certain nuclear instrumentation circuits. Therefore, the Cable Condition Monitoring Program periodically tests nuclear instrumentation circuits to provide an indication of the cable insulation condition, which meets the intent of this NUREG-1801 aging management program element.

- Inaccessible Non-EQ Medium-Voltage Cables

  A representative sample of in-scope, inaccessible medium-voltage cables not designed for submergence subject to prolonged exposure to significant moisture and significant voltage are tested once every 10 years to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function. As stated in NUREG-1801, this is an adequate period to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. The first tests for license renewal are to be completed before the period of extended operation. If an unacceptable condition or situation is identified for an inaccessible medium-voltage cable subject to prolonged exposure to significant moisture and significant voltage in the test sample, a determination would be made as to whether the same condition or situation is applicable to other inaccessible, in-scope, medium-voltage cables.

  This element includes exceptions to NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.” The Cable Condition Monitoring Program requires periodic testing of a representative sample of in-scope, inaccessible medium-voltage cables not designed for submergence subject to prolonged exposure to significant moisture and significant voltage, while the NUREG-1801 program implies all such cables are to be tested. This sampling approach is acceptable for the following reasons.

  Medium-voltage cables at PBNP were ordered moisture resistant for direct buried or underground service, but are not used in direct buried applications. Medium-voltage cables used at PBNP are installed in conduit, duct packs/banks, or manholes, which provide a flow path to drain water (e.g., duct packs/banks are sloped).

  The formation and growth of water trees varies directly with operating voltage. As stated in NUREG-1801, treeing is much less prevalent in 4K VAC cables than those operated at 13 or 33K VAC. Major portions of the higher medium-voltage (13.8K VAC) cables used at PBNP, which are more susceptible to water treeing, were replaced in 1988 with cables ordered moisture resistant for direct buried or underground service. In addition, the 13.8 K VAC cables subject to submergence were successfully tested in 2003 using the Energized Partial Discharge Testing Methodology.

XLPE or high molecular weight polyethylene (HMWPE) insulation materials are most susceptible to water tree formation. Based on a review of cable data, PBNP has no cables with XLPE insulation being operated in the medium-voltage range (i.e., 2K VAC to 15K VAC).

Minimizing exposure to moisture also minimizes the potential for the development of water treeing. Manhole flooding and groundwater intrusion has been a long standing issue at PBNP and efforts were periodically taken to reduce the exposure of medium-voltage cables to water. In order to better understand the magnitude of the groundwater intrusion problem into the electrical manholes, a new call-up to inspect and pump the flooded manholes was initiated. The new call-up periodically inspects and pumps down the electrical manholes, as necessary. As part of the new call-up, the approximate water level in each manhole is recorded. The recording of the water level will provide the basis for any future changes in frequency to the call-up and any deletion of manhole inspections.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

Trending actions are not included as part of this program because the ability to trend inspection or test results is limited and dependent on the specific type of test chosen.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” and XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Acceptance Criteria

- Accessible Non-EQ Electrical Cables and Connections

  The accessible cables and connections are to be free from unacceptable, visual indications of surface anomalies, which suggest that conductor insulation or connection degradation may exist. An unacceptable visual indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

- Non-EQ Electrical Cables Used in Nuclear Instrumentation Circuits

  The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested in the nuclear instrumentation circuits.

  This element includes exceptions to NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.” The NUREG-1801 program indicates that the acceptance criteria are specified in the plant technical specifications. However, the surveillance tests required by the PBNP technical specifications do not include the electrical cables for certain nuclear instrumentation circuits. Therefore, the Cable Condition Monitoring Program periodically tests nuclear instrumentation circuits to provide an indication of the cable insulation condition, which meets the intent of this NUREG-1801 aging management program element.

- Inaccessible Non-EQ Medium-Voltage Cables

  The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested.

  This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

- Accessible Non-EQ Electrical Cables and Connections

  All unacceptable visual indications of cable and connection jacket surface anomalies are subject to an assessment. Such an assessment is to consider the age and operating environment of the component, as well as the severity of the anomaly and whether such an anomaly has previously been correlated to degradation of conductor insulation or connections. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, or relocation or replacement of the affected cable or connection. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections.

- Non-EQ Electrical Cables Used in Nuclear Instrumentation Circuits

  An assessment is performed when the test acceptance criteria are not met in order to ensure that the intended functions of the electrical cables used in nuclear instrumentation circuits can be maintained consistent with the current licensing basis. Such an assessment is to consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root cause for not meeting the test acceptance criteria, the corrective actions required, and the likelihood of recurrence. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other cables used in nuclear instrumentation circuits.

- Inaccessible Non-EQ Medium-Voltage Cables

  An assessment is performed when the test acceptance criteria are not met in order to ensure that the intended functions of the electrical cables can be maintained consistent with the current licensing basis. Such an assessment is to consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root cause for not meeting the test acceptance criteria, the corrective actions required, and the likelihood of recurrence. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other inaccessible, in-scope, medium-voltage cables.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” and XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” and XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Administrative Controls

The Cable Condition Monitoring Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” and XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Operating Experience

Industry operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizers or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indicators of degradation.

Industry operating experience has also shown that visual inspections of non-EQ instrumentation circuit cables within the scope of license renewal are adequate to identify aging degradation, as documented in SAND96-0344, “Aging

Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations.” Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced insulation resistance. Reduced insulation resistance can cause an increase in leakage currents between conductors and from individual conductors to ground. A significant reduction of insulation resistance is a concern for circuits with sensitive, high voltage, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in the instrument circuits.

XLPE or high molecular weight polyethylene (HMWPE) insulation materials are most susceptible to water tree formation. The formation and growth of water trees varies directly with operating voltage. As stated in NUREG-1801, treeing is much less prevalent in 4K VAC cables than those operated at 13 or 33K VAC. In addition, minimizing exposure to moisture minimizes the potential for the development of water treeing.

Plant-specific operating experience has shown that adverse localized environments caused by heat and moisture exist at PBNP. For example, the 4K VAC feeds to the Steam Generator Feed Pumps and from X04 have been exposed to adverse localized environments caused by heat and moisture, respectively. Maintenance work orders were generated to test and/or replace cables and connections that showed signs of aging due to adverse localized environments, as required.

Electrical cables associated with radiation monitoring instrumentation within the scope of license renewal at PBNP are either environmentally qualified in accordance with 10 CFR 50.49 or not installed in adverse localized environments (e.g., radiation monitoring instrumentation associated with the Control Room). Non-EQ electrical cables used in nuclear instrumentation circuits within the scope of license renewal are included within the scope of the Cable Condition Monitoring Program. Operating experience has shown that anomalies found during cable testing can be caused by the degradation of the nuclear instrumentation circuit cable and are a possible indication of potential cable degradation.

Plant-specific operating experience has shown that changes to nuclear instrumentation (NI) cable are gradual and minimal over a long period of time. PBNP Unit 1 has operated for 33 years and Unit 2 has operated for 31 years without any direct failure in the NI cabling. Rather, particular cables have exhibited varying degrees of noise, decreased insulation resistance (IR), and, in one case, a conductor to shield short. These conditions have decreased the signal quality but not interrupted or impaired the accuracy of the indication. In some cases of noise and reduced IR, this condition has been tracked over several years and little additional degradation has been observed. In the case of the conductor to shield short, the cable was abandoned and a spare cable connected to re-establish the circuit.

For all NI instrumentation, the cable that is routed from the detector in close proximity to the reactor vessel to a junction box outside the shield wall consists of mineral insulated cabling. It is connected directly to and an integral part of the detector. When a detector is replaced this portion of cabling is also replaced. Thus the cabling in the most adverse operating environment is not subject to aging and periodically replaced. Connections are accomplished inside of junction boxes, which provide physical and environmental protection for the NI connectors. NI cabling outside of the containment is not routed in an adverse operating environment.

Plant-specific operating experience has also shown that manholes with cables are subject to flooding. Manhole flooding and groundwater intrusion has been a long standing issue at PBNP and efforts were periodically taken to reduce the exposure of medium-voltage cables to water. In order to better understand the magnitude of the groundwater intrusion problem into the electrical manholes, a new call-up to inspect and pump the flooded manholes was initiated. The new call-up periodically inspects and pumps down the electrical manholes, as necessary. As part of the new call-up, the approximate water level in each manhole is recorded. The recording of the water level will provide the basis for any future changes in frequency to the call-up and any deletion of manhole inspections. In addition, a number of cables subject to submergence were successfully tested in 2003 using the Energized Partial Discharge Testing Methodology.

Based on a review of cable data, PBNP has no cables with XLPE insulation being operated in the medium-voltage range (i.e., 2K VAC to 15K VAC).

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Cable Condition Monitoring Program.

An NRC Inspection Report identified a finding regarding inadequate and untimely corrective actions relating to flooding of manholes containing safety and non-safety related cables. The inspectors reviewed corrective actions associated with flooded manholes containing electrical cables. Since 1997, numerous corrective action program documents have been written relating to flooded manholes, submerged cables in manholes, ice formation due to flooded manholes, effects of water on cables, and spurious alarms relating to manholes. Based on the number of corrective action program documents and associated ineffective corrective actions, the inspectors concluded that the licensee had not implemented effective corrective actions to address the problem of cables flooded in manholes.

A condition evaluation was performed as a result of questions raised during the inspection. In order to better understand the magnitude of the groundwater intrusion problem into the electrical manholes, a new call-up to inspect and pump the flooded manholes was initiated. The new call-up periodically inspects and pumps down the electrical manholes, as necessary. As part of the new call-up, the approximate water level in each manhole is recorded. The recording of the water level will provide the basis for any future changes in frequency to the call-up and any deletions of manhole inspections. Based on the corrective actions taken to evaluate pumping out the manholes throughout the year and to evaluate the need to inspect other manholes for similar conditions, the NRC finding was closed. A solution to prevent manhole and cable vault flooding is currently being pursued.

An NRC Inspection Report also identified an Unresolved Item concerning the effects of prolonged water submergence on 13.8K VAC, 4160 VAC, and 480 VAC electrical cables. The NRC determined that this issue did not represent an immediate safety concern. However, they were concerned that if the condition were left uncorrected it would become a more significant safety concern in subsequent years if cable degradation were to interrupt the continuity of offsite power to the safeguards electrical buses. In response to these concerns, a number of these cables, including all of the 13.8K VAC cables subject to submergence, were successfully tested in 2003 using the Energized Partial Discharge Testing Methodology. These cables will also be tested in the future in accordance with the test vendor's recommendations using a proven testing methodology. In addition, actions have been taken to prevent further cable submergence. Based upon these actions, the NRC closed this URI during the third quarter 2003

As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.E1, “Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” XI.E2, “Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” and XI.E3, “Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Conclusion

The Cable Condition Monitoring Program provides reasonable assurance that the applicable aging effects will be managed such that the intended functions of electrical cables and connections within the scope of license renewal that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat, radiation, or moisture are maintained consistent with the current licensing basis through the period of extended operation.

The Cable Condition Monitoring Program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The scope of this program includes accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal. Inspections and tests using techniques with a demonstrated capability are used to detect the aging effects of concern. Periodic actions are also taken to prevent cables from being subject to prolonged exposure to significant moisture, such as inspecting for water collection in cable manholes and draining water, as needed.

B2.1.9 Closed-Cycle Cooling Water System Surveillance Program

Program Description

The Closed-Cycle Cooling Water System Surveillance Program manages aging effects in closed cycle cooling water systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink. The program includes (a) maintenance of system corrosion inhibitor concentrations to minimize degradation, and (b) periodic or one-time surveillance testing and inspections to evaluate system and component performance. Inspection methods may include visual, ultrasonic (UT) and eddy current (ECT) testing.

Component Cooling (CC) Water System

The program relies on mitigative measures to minimize corrosion and microbiological growth through the addition of chromates and maintenance of water chemistry within specified limits. The chemicals added are potassium dichromate, as a corrosion inhibitor, and potassium hydroxide to maintain pH. The program monitors the performance of selected heat exchangers by performing heat balance testing to verify the thermal performance function; it credits the One-Time Inspection Program for the inspection of selected heat exchangers and a representative sample of stagnant portions of the system piping. The inspections will check for fouling and evidence of corrosion or cracking. Nondestructive examinations may be used to verify pipe wall thickness at selected locations where loss of material has been experienced. The program requires system pressure tests to locate and identify leaks so that corrective actions can be taken. The program also directs monitoring of system and component flow to verify that components are receiving the required flow of cooling water.

Emergency Diesel Generator Coolant Sub-systems

The program relies on mitigative measures to minimize corrosion in the engine coolant sub-systems through the use and maintenance of corrosion inhibitors. Engine performance is verified by periodic surveillance tests. This program credits the One-Time Inspection Program to perform an inspection and condition assessment of various components in the EDG coolant sub-systems.

Gas Turbine Generator (G05) and Associated Diesels

The program relies on mitigative measures to minimize corrosion in the engine coolant sub-systems through the use and maintenance of corrosion inhibitors. Equipment performance is verified by periodic surveillance tests. This program credits the One-Time Inspection Program to perform an inspection and condition assessment of various components in the coolant sub-systems.

Ventilation Chilled Water Sub-systems

The program relies on mitigative measures to minimize corrosion in the chilled water sub-systems through the use and maintenance of corrosion inhibitors. The chilled water sub-systems are normally in continuous operation. Equipment performance is monitored periodically. This program credits the One-Time Inspection Program to perform an inspection and condition assessment of various components in the chilled water sub-systems.

NUREG-1801 Consistency

The Closed-Cycle Cooling Water System Surveillance Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M21, “Closed-Cycle Cooling Water System” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Preventive Actions
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Monitoring and Trending
- Acceptance Criteria

Enhancements

Enhancements to the Closed-Cycle Cooling Water System Surveillance Program include the revision of applicable procedures and/or Callups to ensure consideration of the applicable aging effects and to establish sampling periodicity and criteria for the coolant associated with the Gas Turbine and related diesel engines, and applicable ventilation chilled water sub-systems. This is being done to ensure the appropriate concentration of corrosion inhibitor is being maintained in the coolant. Enhancements also include: a review of the acceptable chloride and fluoride levels in the CC System, the creation of procedural requirements for operating the system within the established acceptance ranges for the applicable chemical parameters, and the completion of a strategy for a long-term condition assessment of the CC Heat Exchangers because of suspected galvanic corrosion of the tube support plates. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Closed-Cycle Cooling Water System Surveillance Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M21, “Closed-Cycle Cooling Water System,” is also provided below.

Scope of Program

The Closed Cycle Cooling Water System Surveillance Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Chemical and Volume Control	Essential Ventilation
Class 1 Piping/Components	Non-Class 1 RCS Components
Component Cooling Water	Residual Heat Removal
Containment Spray	Safety Injection
Emergency Power	Waste Disposal

The Closed-Cycle Cooling Water System Surveillance Program pertains to closed systems that are not subject to significant sources of contamination, in which the water chemistry is controlled, monitored, and kept within specified limits, and in which the heat is not directly rejected to the ultimate heat sink. The program is applicable to the Component Cooling (CC) Water System, the EDG coolant sub-systems, Gas Turbine, Gas Turbine associated diesel cooling sub-systems, and the chilled water sub-systems for the Control Room, Computer Room, and Cable Spreading Room.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

The program, as applied to the CC System, relies on the use of appropriate materials and a water treatment program to inhibit corrosion. Potassium dichromate is used as the corrosion inhibitor in the CC System and the chromate concentration limits stated in plant procedures fall within the typical control range provide in Table 4.2 of EPRI TR 107396 (Reference 12). The program includes monitoring and control of the CC System chemistry to minimize exposure to aggressive environments and to mitigate corrosion.

The EDG, Gas Turbine, Gas Turbine associated diesels cooling sub-systems, and the ventilation chilled water sub-systems use commercial corrosion inhibitors. EPRI TR 107396 discusses these in general terms, but does not provide specific concentration limits for the two products in use. PBNP maintains the concentration limits within the manufacturer’s recommended range.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The exception is that the EDG and Gas Turbine related cooling sub-systems, and the ventilation chilled water sub-systems corrosion inhibitor concentrations are maintained in accordance with the manufacturer’s recommendation, not EPRI TR 107396.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The Closed-Cycle Cooling Water System Surveillance Program periodically monitors CC System chemistry to verify it is being maintained within specified limits. The parameters monitored are pH, chloride, fluoride, chromate and sulfate concentrations, conductivity, and radioactivity. The system flows are monitored, as are pump suction and discharge pressure. Selected heat exchangers are monitored for flow. Selected heat exchangers are also heat balance tested. The smaller heat exchangers, such as the seal water heat exchangers on the containment spray pumps, residual heat removal pumps, and the safety injection pumps and the sample system heat exchangers, do not have the capability of performing a heat balance test. Flows through these heat exchangers are set within specified ranges so that they are capable of performing their intended function.

Periodic performance of system pressure testing of the CC System verifies that the pressure boundary function of the components in the CC System is maintained. This test is used to identify leaks and correct them prior to a loss of system or component intended function.

The EDG coolant sub-systems are periodically sampled and analyzed to maintain the corrosion inhibitor concentration within the manufacturer’s recommended range. The coolant in G01 and G02 is also checked for pH, microbiological contamination, conductivity, total suspended solids, iron, copper, calcium and magnesium. Engine coolant temperatures are recorded during the monthly surveillance tests.

The Gas Turbine and associated diesels coolant sub-systems are periodically sampled and analyzed to maintain the corrosion inhibitor concentration within the manufacturer’s recommended range. The equipment is periodically started, put on line, and loaded to verify operability.

The ventilation chilled water sub-systems are periodically sampled and analyzed to maintain the corrosion inhibitor concentration within the manufacturer's recommended range. The system performance is periodically monitored by checking system pressures and temperatures.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The NUREG-1801 element states that the parameters monitored/inspected are in accordance with standards in EPRI TR-107396. PBNP does not reference this document in any of the CC System, EDG, Gas Turbine, or chilled water sub-system procedures, nor are all of the parameters listed in the EPRI document monitored. The EPRI document states that "The system impurities that could be monitored are chlorides, fluorides, sulfates, corrosion products, calcium and magnesium, refrigerant chemicals, and radionucleides." In addition, the EPRI document states that the chemical treatment control parameters that are frequently monitored include pH, conductivity, and corrosion inhibitors. PBNP does not monitor the CC System for corrosion products, calcium and magnesium, or refrigerant chemicals, however the remaining water chemistry parameters are monitored. In addition, NUREG-1801 states "For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure." The parameters stated in NUREG-1801 are not monitored for all heat exchangers, only on a selected few in the CC System. Flow and pressure drop are monitored for groups of heat exchangers in the CC System, not for individual heat exchangers. Plant-specific operating experience has not demonstrated the need to monitor the additional parameters referenced in the EPRI report. Not all of the EPRI chemistry parameters are monitored for the EDG, Gas Turbine, Gas Turbine associated diesels coolant sub-systems, and the ventilation chilled water sub-systems. Also, pump suction or discharge pressure and coolant flows are not monitored for the EDG, Gas Turbine and ventilation related sub-systems. Again, operating experience has shown that additional monitoring is not needed.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Detection of Aging Effects

NUREG-1801 states that "The extent and schedule of inspections and testing in accordance with EPRI TR-107396, assure detection of corrosion before the loss of intended function on the component. Performance and functional testing in accordance with EPRI TR-107396, ensures acceptable functional testing of the

CCCW System or components serviced by the CCCW System." The One-Time Inspection Program is credited with the detection of corrosion in areas of stagnant flow conditions in the CC System. Periodic heat transfer testing of the CC heat exchangers provides indication of fouling. Various CC System operating parameters such as pressure, flow and surge tank volume are monitored and will provide indication of system degradation.

The EDGs, Gas Turbine, and Gas Turbine associated diesels are not normally in operation, but are periodically tested to ensure operability. Internal inspections of portions of the engines coolant sub-system will be performed via the One-Time Inspection Program. The ventilation chilled water sub-systems are normally in operation and system performance is periodically checked. Internal inspections of select components will be performed via the One-Time Inspection Program.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. PBNP meets the intent of the EPRI report by monitoring CC water flows through critical heat exchangers and monitoring the overall system performance. The EPRI report also states that microbiological testing is performed on the bulk water in the CC System (planktonic organisms). The test can be performed to provide a good indication of trends in general microbiological control. Microbiological testing is performed on the nitrate based coolant used in G01 and G02 because this type of coolant is susceptible to microbiological contamination. PBNP does not perform this type of test on the CC System, ventilation chilled water sub-systems, or the coolant sub-systems for G03 and G04. As previously stated the chromates in the CC System are toxic to microbiological organisms and plant experience has shown no problems with microbiological growth in the CC System. The glycol concentration in the ventilation chilled water sub-systems, G03, G04, G05, G-500, and G-501 is maintained at a level where biological growth is inhibited. These preventive actions preclude the need to perform microbiological testing.

Enhancements to plant documents include revisions to ensure consideration of the applicable aging effects and to establish sampling periodicity and criteria for the coolant associated with the Gas Turbine and related diesel engines, and applicable chilled water sub-systems. This is being done to ensure the appropriate concentration of corrosion inhibitor is being maintained in the coolant. Enhancements also include: a review of the acceptable chloride and fluoride levels in the CC System, the creation of procedural requirements for operating the system within the established acceptance ranges for the applicable chemical parameters, and the completion of a strategy for a long-term condition assessment of the CC Heat Exchangers because of suspected galvanic corrosion of the tube support plates.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

The CC System water chemistry is sampled on a periodic basis and as indicated by plant operating conditions. Performance of the CC System is monitored with the in-place instrumentation. System pressure tests are performed per plant procedures. The frequency of the thermal balance testing of the CC/SW heat exchangers is performed in accordance with plant procedures. Plant procedures are used to set flows to heat exchangers or a group of heat exchangers, except for pump seal coolers.

The EDG and Gas Turbine related coolant sub-systems are sampled on a periodic basis. Performance tests are periodically conducted. Testing of specific heat exchangers to determine heat removal capability is not performed.

The ventilation chilled water sub-systems are sampled on a periodic basis. System performance is periodically checked. Testing of specific heat exchangers to determine heat removal capability is not performed.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 states that performance and functional tests are performed at least once every 18 months to demonstrate system operability, and tests to evaluate heat removal capability of the system and degradation of system components are performed every five years. PBNP takes exception to these requirements. CC System operability is monitored with the installed instrumentation, as mentioned above. Operating experience has shown that the CC System does not have corrosion or fouling build-up on the internal surfaces of its components. Therefore, PBNP will perform tests as a result of CC System performance evaluations by the responsible engineer and not commit to a specific periodicity. PBNP does not routinely perform heat removal capability tests on the EDG and Gas Turbine related coolant sub-systems, however operability testing is periodically conducted. PBNP also does not routinely perform heat removal capability tests on the ventilation chilled water sub-systems. These systems are normally in continuous operation and system operating parameters are periodically checked to assess system performance.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Acceptance Criteria

CC System water chemistry is maintained within the limits specified in plant procedures, which are consistent with the values in EPRI TR-107396 for the parameters that are monitored at PBNP. Acceptance criteria for the ventilation chilled water sub-systems, EDG and Gas Turbine related coolant chemistry are in accordance with the manufacturer's recommendations. System and component inspection and performance results are evaluated against design values and corrective actions are taken when deemed necessary by the responsible engineer(s).

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The exception is that the ventilation chilled water sub-systems, EDG, and Gas Turbine related coolant chemistry acceptance criteria are based on the manufacturer's recommendations, not EPRI TR-107396.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Closed-Cycle Cooling Water System Surveillance Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

Plant-specific operating experience indicates that CC System performance has been very good. PBNP has not experienced degradation of its CC System due to corrosion product build up or cracking. The chromate water treatment in the CC System has performed satisfactorily in mitigating loss of material and loss of heat transfer. Routine checks performed on the CC System by operators, such as monitoring flows through heat exchangers, monitoring system pressures at various locations, monitoring pump suction and discharge pressure, and monitoring temperatures of both the CC System and the components that the CC water is cooling, ensure early detection of CC System problems that will lead to corrective actions. The performance of a system pressure test is used to detect and eliminate unacceptable leaks.

Tube vibration in the CC Heat Exchangers has been documented in the corrective action program. The vibration has been attributed to increased clearances in the tube to tube support plate interface. The CC Heat Exchangers were re-tubed with SeaCure tube material, which creates the potential for galvanic corrosion of the carbon steel tube support plates. Galvanic corrosion of the tube support plates is believed to be the reason for the increased clearances and subsequent tube vibration at high CC flows. A long-term condition assessment strategy for the CC Heat Exchangers is being developed regarding this issue.

Trending of nitrite and microbiological levels in the engine coolant of G01 and G02 EDGs has revealed slight in-leakage of service water into the engine coolant. This resulted in the heat exchangers being inspected and repaired or replaced. Periodic nitrate depletion in G02 is an open issue that is being addressed via the corrective action process.

There have been no significant degradation problems with the coolant sub-systems of EDG G03 and G04, the Gas Turbine and associated equipment, and the ventilation chilled water sub-systems. The Closed-Cycle Cooling Water System Surveillance Program provides reasonable assurance that these sub-systems and components will continue to perform their intended functions.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Closed-Cycle Cooling Water System Surveillance Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Closed-Cycle Cooling Water System Surveillance Program provides reasonable assurance that aging effects, such as loss of material, loss of heat transfer, and cracking will be adequately managed such that systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

The Closed-Cycle Cooling Water System Surveillance Program uses various methods to ensure that systems and components will continue to perform their intended functions. Thermal performance testing on selected heat exchangers is used to verify that they can continue to perform the heat removal intended function. Monitoring of chemistry and maintaining parameters within specified limits ensures that corrosion and biofouling are minimized. Inspections performed under the One-Time Inspection Program will verify the effectiveness of the water chemistry controls.

B2.1.10 Fire Protection Program

Program Description

The Fire Protection Program includes (a) fire barrier inspections, (b) electric and diesel-driven fire pump tests, (c) periodic inspection and testing of the halon fire suppression system, and (d) periodic maintenance, testing, and inspection of water-based fire protection systems. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed to ensure that functionality and operability is maintained. Periodic testing of the electric and diesel-driven fire pumps ensures that an adequate flow of firewater is supplied and that there is no degradation of diesel fuel supply lines. Periodic maintenance, testing and inspection activities of water-based fire protection systems provides reasonable assurance that fire water systems are capable of performing their intended function. Inspection and testing is performed in accordance with the nuclear insurance carrier's fire protection system testing requirements and generally follows the guidance of applicable NFPA Codes and Standards, as described in the PBNP Fire Protection Evaluation Report.

This program credits the Buried Services Monitoring Program for the management of aging effects on the external surfaces of buried fire water system piping.

NUREG-1801 Consistency

The Fire Protection Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.M26, “Fire Protection,” and XI.M27, “Fire Water System,” (Reference 3) as clarified by ISG-04, “Aging Management of Fire Protection Systems for License Renewal.”

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Preventive Actions
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Monitoring and Trending
- Acceptance Criteria

Enhancements

Enhancements to the Fire Protection Program include revisions to various existing implementing documents to add specific inspections, monitoring and trending requirements, and/or frequency adjustments based on operating experience. Additionally, new implementing documents will be created to cause inspections of selected components and portions of the fire suppression piping. An evaluation will be performed to determine which non-Appendix R/Safe Shutdown fire dampers may need to be added to the program. These enhancements are required to satisfy the NUREG-1801 aging management program requirements as clarified by ISG-04. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Fire Protection Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.M26, “Fire Protection,” and XI.M27, “Fire Water System,” as clarified by ISG-04, “Aging Management of Fire Protection Systems for License Renewal,” is also provided below.

Scope of Program

The Fire Protection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Circulating Water Pumphouse Structure	Fire Protection
Control Building Structure	Primary Auxiliary Building Structure
Diesel Generator Building Structure	Service Water
Fire Barrier Commodity Group	

The Fire Protection Program is credited for managing the aging effects of water-based fire protection systems exposed to lake water. The Fire Protection Program is also credited for detecting and managing age-related degradation of fire barrier walls, ceilings, and floors, penetration seals, fire-doors, and halon fire suppression system components. It also manages the aging effects on the intended function of the fuel supply line for the diesel engine fire pump.

Enhancements to the Fire Protection Program include performing an evaluation to determine which non-Appendix R/Safe Shutdown fire dampers may need to be added to the program.

This element is consistent with the corresponding NUREG-1801 aging management program elements, as clarified by ISG-04.

Preventive Actions

Testing and inspections are conducted to satisfy 10 CFR 50, Appendix R and 10 CFR 50.48 requirements. To minimize corrosion, MIC, or biofouling in fire system components exposed to lake water, periodic flushing of selected piping, system performance testing and inspections are performed. Planned evolutions which cause significant quantities of lake water to enter the fire water system (e.g., testing, flushing) are administratively controlled such that the chlorination system is in operation if the circulating water inlet temperature is $\geq$ 45 degrees F. This is done to control the infestation of biological organisms into the fire water system.

This element is consistent with the corresponding NUREG-1801, Section XI.M27 aging management program element, as clarified by ISG-04.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M26 aging management program element, as clarified by ISG-04. The corresponding element in NUREG-1801, Section XI.M26 and ISG-04 describes the objectives of the fire hazard analysis. The PBNP Fire Protection Evaluation Report does address the listed considerations for fire prevention, fire detection, fire suppression, fire containment, and alternate shutdown capability. However, these general Fire Protection Evaluation Report requirements do not manage or prevent aging effects of the associated components and consequently are not addressed in this aging management program.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element, as clarified by ISG-04.

Parameters Monitored or Inspected

Visual examinations of fire barrier walls, ceilings, and floors are performed on a 4.5 year frequency (approximately one third every 18 months) to ensure timely detection of degradation of fire barriers (e.g., cracking, spalling, loss of material) and fire barrier penetration seals. The inspection will detect cracks, separation from building structures and components, and rupture or puncture of the seals. An inspection of at least 10% of the fire dampers is performed on an 18 month frequency. If any sign of degradation is detected within the 10% sample, the scope of the inspection is expanded to ensure timely detection of damper degradation before a loss of intended function. Fire doors are periodically tested and visually inspected for signs of corrosion, wear, or missing parts to ensure that functionality and operability is maintained. The clearance at the bottom of the door is included in the inspection. Other door clearances are not specifically measured, but are considered acceptable if the door functions properly. The inspections also check for holes in the door or frame, loose or damaged weatherstripping, threshold inserts, bottom door inserts, or sweeps.

An annual fire pump capacity test is performed to ensure that the diesel-driven and the electric motor-driven fire pumps are performing adequately and meet the requirements specified in the Fire Protection Evaluation Report. The fuel oil supply line to the diesel-driven fire pump is visually inspected for signs of degradation.

Halon system tests and inspections ensure the operability of the fire suppression system protecting the affected fire zones. Accessible components are also visually inspected for corrosion or other degradation.

Various inspections and tests are performed to verify the fire protection system's ability to maintain its intended function. Pump full flow capacity tests, the flushing of components, the fire system's ability to maintain pressure and periodic internal inspections and/or wall thickness measurements of selected portions of the system are the parameters monitored.

This element is consistent with the corresponding NUREG-1801, Section XI.M27 aging management program element, as clarified by ISG-04.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M26 aging management program element, as clarified by ISG-04. NUREG-1801, Section XI.M26 and ISG-04 state that visual inspections of approximately 10% of each type of fire barrier penetration seal are performed at least once every refueling outage. As discussed above, these inspections are performed on a 4.5 year frequency with approximately one third of the seals inspected every 18 months.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element, as clarified by ISG-04.

Detection of Aging Effects

Visual examinations of fire barrier walls, ceilings, and floors are performed on a 4.5 year frequency (approximately one third every 18 months) to ensure timely detection of degradation of fire barriers (e.g., cracking, spalling, loss of material) and fire barrier penetration seals. The inspection will detect cracks, separation from building structures and components, and rupture or puncture of the seals. An inspection of at least 10% of the fire dampers is performed on an 18 month frequency. If any sign of degradation is detected within the 10% sample, the scope of the inspection is expanded to ensure timely detection of damper degradation before a loss of intended function. Fire doors are periodically tested and visually inspected for signs of corrosion, wear, or missing parts to ensure that functionality and operability is maintained.

Annual testing of the fire pumps is performed to ensure that an adequate flow of fire water is supplied and that there is no degradation of the fuel line to the diesel-driven fire pump.

The Halon fire suppression system surveillance test is conducted on a semiannual basis. The test includes testing the related smoke detectors, the heat actuated devices, and the proper operation of system components. Visual inspections of accessible components are also conducted.

Continuous fire water system pressure monitoring, periodic system flow testing, periodic functional testing including fire detection/actuation devices (e.g., HADs, heat detectors, etc.), and internal inspections and wall thickness evaluations of selected portions of the system ensure that corrosion and biofouling are not occurring to an extent that an intended function would be compromised. In lieu of full flow testing of the sprinkler piping, PBNP will perform wall thickness evaluations (e.g., non-intrusive volumetric testing) on a representative number of locations before the period of extended operation and at specified intervals thereafter. The inspection intervals will be determined based on an evaluation of the inspection results. Conditions of the internal surfaces of the above ground piping are considered representative of the internal surfaces of below ground piping, because the material and environment is similar.

Sprinkler heads will either be replaced or tested in accordance with NFPA 25 prior to exceeding their 50 year service life. If the sprinkler heads are not replaced, the required testing will be repeated at 10 year intervals.

Monthly visual inspections of fire hydrants and annual fire hydrant flow tests provide the opportunity for degradation to be detected before a loss of intended function can occur.

This element includes exceptions to the corresponding NUREG-1801 aging management program elements, as clarified by ISG-04.

NUREG-1801, Section XI.M26, as clarified by ISG-04, states that visual inspections of approximately 10% of each type of fire barrier penetration seal is inspected at least once every refueling outage. As discussed above, these inspections are performed on a 4.5 year frequency with approximately one third of the seals inspected every 18 months. PBNP does not qualify the personnel performing the visual inspections of fire barrier walls, ceilings, floors, penetration seals and fire doors to the NDE type of qualification as stated in NUREG-1801 and ISG -04. Inspectors for fire barriers/doors/fire seals are qualified to perform those inspections, but are not necessarily qualified to VT-1 or VT-3. There are no regulatory requirements or any other type of requirements specifying that these inspections be performed to VT-1 or VT-3 standards.

NUREG-1801, Section XI.M27, as clarified by ISG-04, requires annual visual inspections of yard fire hydrants per NFPA 25 and annual hydrant flow tests, gasket inspections, and hose hydrostatic tests. PBNP performs monthly yard hydrant inspections and annual flushing of yard fire hydrants, but not necessarily in accordance with NFPA 25. PBNP checks the flow capacity of the main fire loop, but does not measure individual hydrant flow. Fire hose and gaskets are considered short lived components and are not subject to aging management.

Enhancements to the Fire Protection Program include revisions to various existing implementing documents to add specific inspections, monitoring and trending requirements, and/or frequency adjustments based on operating experience. For example, enhancements will be made to:

- add a step to state that the fuel oil lines from the day tank to the diesel engine will be inspected for evidence of corrosion or leaks whenever the fire pump capacity test is conducted.
- state that personnel shall perform a walkdown inspection of accessible halon system components. The inspections will check for signs of mechanical damage and corrosion.
- add a step to state that fire system components are to be inspected for evidence of corrosion, leakage, or damage during the process of verifying valve stroking and position.
- add a step to state that the exposed system shall be inspected for signs of corrosion, leakage, or damage to any components of the fire system during the performance of hydrant flushing.
- include inspection and acceptance criteria for industrial fire door clearances.
- include specific inspections of concrete fire barrier walls for cracking, spalling, and loss of material, and to include visual inspection of fire dampers for general corrosion.

New implementing documents will also be created to cause inspections of selected components and portions of the fire suppression piping.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements, as clarified by ISG-04.

Monitoring and Trending

Visual examinations of fire barrier walls, ceilings, floors, and penetration seals are performed on a 4.5 year frequency (approximately one third every 18 months) to ensure timely detection of degradation of fire barriers (e.g., cracking, spalling, loss of material) and fire barrier penetration seals. The inspection will detect cracks, separation from building structures and components, and rupture or puncture of the seals. An inspection of at least 10% of the fire dampers is performed on an 18 month frequency. If any sign of degradation is detected within the 10% sample, the scope of the inspection is expanded to ensure timely detection of damper degradation before a loss of intended function. Fire doors are periodically tested and visually inspected for signs of corrosion, wear, missing parts, and proper clearances to ensure that functionality and operability is maintained. Based on operating experience, the frequencies assigned in the plant procedures are adequate to verify that the intended function of these components is maintained until the next scheduled inspection.

The performance of the diesel-driven fire pump is monitored during the annual pump capacity test to detect any degradation in the fuel supply line (e.g., if the diesel-driven fire pump does not receive an adequate amount of fuel flow, it will not be able to achieve the required head/flow results).

The Halon fire suppression system is periodically tested and inspected to detect any degradation in the system. These semiannual tests provide the data necessary for trending.

The fire protection system pressure is continuously monitored. Test results from the various surveillance tests are evaluated. Periodic full flow flushing of the main fire system underground piping is performed to assure that corrosion is not occurring and the system function is maintained. Any degradation identified either by visual inspections or as a result of testing is evaluated and corrected.

This element includes exceptions to the corresponding NUREG-1801 aging management program elements, as clarified by ISG-04. NUREG-1801, Section XI.M26, as clarified by ISG-04, states that visual inspections of fire barrier penetration seals are performed every refueling outage. As discussed above, these inspections are performed on a 4.5 year frequency with approximately one third of the seals inspected every 18 months.

NUREG-1801, Section XI.M27, as clarified by ISG-04, states that the results of system performance testing are monitored and trended as specified by the NFPA codes and standards. At PBNP, inspection and testing is performed in accordance with the nuclear insurance carrier's fire protection system testing requirements and generally follows the guidance of applicable NFPA Codes and Standards, as described in the PBNP Fire Protection Evaluation Report.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements, as clarified by ISG-04.

Acceptance Criteria

Acceptance criteria are defined in the PBNP procedures used to perform tests and inspections of the fire protection system. Fire seal and conduit wrapping inspection results are acceptable if there are no visual indication of cracking, separation of seals from building structures and components, rupture or puncture of seals. Fire damper inspections are acceptable if there are no signs of degradation due to general corrosion. Concrete wall, floor, and ceiling inspection results are acceptable if there are no visual indications of concrete cracking, spalling and loss of materials. Fire door inspection results are acceptable if there are no visual indications of wear, holes, damaged or missing parts, and clearances are within limits. Diesel-driven fire pump inspections are acceptable if there is no evidence of corrosion or leaks on the fuel oil supply line. Acceptance criteria for the diesel-driven fire pump capacity is contained within the test procedure. Halon fire suppression system inspection results are acceptable if there are no signs of corrosion or damage to the components.

The fire water system pressure is continuously monitored through alarm setpoints. Acceptance criteria are established for wall thickness and internal visual inspections of system components.

This element is consistent with the corresponding NUREG-1801, Section XI.M26 aging management program element, as clarified by ISG-04.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M27 aging management program element, as clarified by ISG-04. NUREG-1801, Section XI.M27, as clarified by ISG-04, states “that no biofouling exists in the sprinkler systems that could cause corrosion in the sprinkler heads.” PBNP does not specifically examine system components for biofouling, however sprinkler head corrosion from any cause would be identified during the planned sprinkler head inspections or replacements.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element, as clarified by ISG-04.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program elements, as clarified by ISG-04.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements, as clarified by ISG-04.

Administrative Controls

The Fire Protection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements, as clarified by ISG-04.

Operating Experience

A search of plant-specific operating experience has shown that after thirty plus years of operation the Fire Protection System has performed well. There have been some cases of small pipe threaded connection leaks, small pipe external corrosion leaks, spray nozzles for the transformer deluge system plugged due to rust scale build-up, and cracked piping and fittings. Pinhole leaks have also been found on the 10 inch fire water supply header and sprinkler heads have been found to leak. These discrepancies were discovered in the last 13 years and were repaired using maintenance work orders. The inspections performed on the fire hydrants did reveal that three hydrants were found to be stuck shut over a ten year inspection period. None have been found stuck during the last few inspections. Plant-specific operating experience has indicated that below grade fire system piping leaks are very rare. The sandy soil condition is such that it is not conducive to high rates of corrosion and the Lake Michigan water used for the fire protection system is not aggressive to the internal surfaces of the piping.

Fire doors are occasionally found in need of repair. Some of the electrical penetration fire seals in containment were also found in need of repair. In general, the surveillance tests, inspections, and maintenance required to meet applicable codes and standards have demonstrated reliable performance of the fire protection system.

The Fire Protection Program has been an ongoing program at PBNP. The program has evolved over the years of plant operation and has been enhanced by the implementation of 10 CFR 50, Appendix R and 10 CFR 50.48. The overall effectiveness of the program is demonstrated by the operating experience of systems, structures, and components that are subject to the Fire Protection Program.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 was performed to determine the overall effectiveness of the program. The results of this review indicated that the overall effectiveness of the Fire Protection Program was good.

Over the past several years, the NRC has performed numerous inspections of the fire protection program. The areas of inspection included walkdowns of many fire zones looking for fire protection degradation. The inspectors verified that fire hoses and portable fire extinguishers were installed at their designated locations, were in satisfactory physical condition, and were unobstructed. The inspectors verified the physical location and condition of fire detection devices. Additionally, passive features, such as fire doors, fire dampers, and mechanical and electrical penetration seals were verified to be located per the Fire Protection Evaluation Report and to be in good physical condition. The inspectors also reviewed procedures to verify that inspections were conducted in accordance with the Fire Protection Evaluation Report. The conclusion of these inspections was that there were either no significant findings or the findings were of very low safety significance (i.e., non-cited violations, green or no color).

A 1999 QA Audit was conducted utilizing NRC Inspection Procedure (IP) 64704 as a guide. The audit team concluded that the Fire Protection Program meets station requirements and has sound processes. QA audited eighteen different areas of the Fire Protection Program with seventeen areas found acceptable. A Condition Report (CR) was initiated to track the unsatisfactory item, which was reviewed and resolved by engineering. As part of the audit the QA team inspected fire barriers in six fire zones and found them to be in good condition.

A 2000 QA Audit focused on the fire protection organization, responsibilities, and training requirements. Condition Reports initiated during the previous three audits were reviewed and it was concluded that the concerns expressed during those audits were being appropriately addressed.

A 2001 QA Audit A-P-01-19 was conducted to evaluate key aspects of the Appendix R Safe Shutdown Analysis and the Conventional Fire Protection Program. The audit included assessments of the methodology, input assumptions, supporting calculations, and quality of documentation for the safe shutdown model, systems analysis, and equipment and cable selection. The Fire Protection Program was also evaluated for consistency with industry expectations. Walkdowns were performed of selected fire areas to assess the condition of passive and active fire protection components. Based on the audit activities performed, the Fire Protection Program was found to be effectively documented, implemented, and met industry standards. There was one condition found unacceptable, the combustible loading analysis was found deficient in that the analysis was not traceable to approved engineering documentation and one input used for the analysis was an unapproved revision to a calculation, which also contained unacceptable assumptions. These concerns with the combustible loading analysis were documented in the corrective action program and resolved.

An assessment of the Fire Protection Program was performed by Nuclear Oversight during the third quarter of 2002. This assessment focused on conventional (non-Appendix R) fire protection programs at PBNP and determined that most are adequate, with attention needed in some areas. Management attention was needed regarding the adequacy of resources dedicated to the Fire Protection Engineering Programs Group workload, retrievability of the documented basis for acceptability of penetration seals, and resolution of combustible loading analysis deficiencies. All findings were entered into the corrective action program and resolved.

The review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no other issues or findings that could impact the effectiveness of the Fire Protection Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program elements, as clarified by ISG-04.

Conclusion

The Fire Protection Program provides reasonable assurance that the aging effects of concern will be managed such that SSC within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. This is accomplished by performing the inspections and testing required by the Fire Protection Evaluation Report and the supporting plant procedures. These tests and inspections are performed at established frequencies with well defined acceptance criteria and will provide for early detection of any conditions which might adversely affect the intended function(s) of the SSCs.

B2.1.11 Flow-Accelerated Corrosion Program

Program Description

The Flow Accelerated Corrosion Program manages aging effects due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The program implements the EPRI guidelines in NSAC-202L-R2 (Reference 39) for an effective FAC program and includes (a) an analysis using a predictive code such as CHECWORKS to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm the predictions, and (d) repairing or replacing components, as necessary.

The objectives of this program are to control and monitor FAC, to plan inspections, to prevent failures, and to implement a long-term strategy to reduce loss of material due to FAC. To aid in the planning of inspections and choosing inspection locations, PBNP utilizes the FAC module of CHECWORKS, which is an EPRI computer program developed solely for the management of FAC. The most susceptible components from each system are selected for inspection. The most susceptible material to FAC attack is carbon or low alloy steel.

NUREG-1801 Consistency

The Flow Accelerated Corrosion Program is an existing program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M17 “Flow Accelerated Corrosion.” (Reference 3)

Exceptions to NUREG-1801

None

Enhancements

Enhancements to the Flow Accelerated Corrosion Program include revisions to plant procedures to add specific components to the scope of the program, ensure congruence with the guidelines of NSAC-202L-R2, and provide better references to the input data sets. Enhancements also include clarification of the program requirements for SG nozzles and reducers, and more stringent controls placed on program basis documentation and software. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Flow Accelerated Corrosion Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M17, “Flow Accelerated Corrosion,” is also provided below.

Scope of Program

The Flow Accelerated Corrosion Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Main and Auxiliary Steam
Feedwater and Condensate	Steam Generators

The PBNP FAC program is credited for managing the aging effect of loss of material due to flow accelerated corrosion. This program predicts, detects, and monitors loss of material due to flow accelerated corrosion in high energy carbon and low alloy steel piping associated with the Main and Auxiliary Steam, Feedwater and Condensate, and Auxiliary Feedwater Systems. The program is based on the criteria identified in EPRI NSAC-202L-R2 guidelines and industry experience. The program includes the following activities:

- conduct appropriate analysis and limited baseline inspections;
- determine the extent of thinning and repair or replace components as appropriate;
- perform follow up inspections to confirm or quantify previously discovered conditions; and
- take long term corrective actions if necessary.

The program uses the CHECWORKS Code, which has been found acceptable for FAC analysis.

Procedures will be enhanced to add specific components to the scope of the program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

There are no preventive actions associated with the FAC Program. The program is an inspection, analysis, and verification program. Components with a calculated remaining life of less than one operating cycle are either replaced, repaired, or re-evaluated to ensure FAC will not proceed to the point that the intended function of pressure boundary will be jeopardized.

This element is consistent with the corresponding NUREG-1801 aging management program element

Parameters Monitored or Inspected

The program monitors the effects of FAC on the intended function of piping and components by measuring the wall thickness using nondestructive examinations and by performing analytical evaluations. Prior to each outage the FAC Coordinator uses the CHECWORKS Model to select components for inspection. There are seven basic geometries that are of concern to be selected for inspection, they include straight pipe, elbow, tee, reducer, expander, nozzle, and orifice. All of these geometries are included in the inspection sample.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

The method of inspections is visual, ultrasonic, and/or computed radiography. The inspection schedule provides for timely detection of degradation of susceptible piping and components inspected each refueling outage. Aging degradation of components occurs by wall thinning. The extent and schedule of inspections ensures detection of wall thinning before the loss of the intended function of the component.

Procedures will be enhanced to ensure congruence with the guidelines of NSAC-202L-R2, and provide better references to the input data sets. Enhancements also include clarification of the program requirements for SG nozzles and reducers, and more stringent controls placed on program basis documentation and software.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

CHECWORKS code is used to predict component degradation in systems susceptible to FAC. Plant data, including material composition, system flow characteristics, and operating conditions are also important in determining the remaining service life, which is recalculated after each inspection.

CHECWORKS is acceptable because it provides a bounding analysis for FAC. The inspection schedule developed on the basis of the results of this predictive code provides reasonable assurance that adequate wall thickness will be maintained between inspections.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

Inspection results are used to calculate the number of operating cycles remaining before the component reaches code minimum allowable wall thickness. If calculations indicate that an area will reach code minimum wall thickness before the next inspection interval, the component must be replaced, repaired, or re-evaluated.

The acceptance criteria are well defined in plant procedures. For example, if minimum measured thickness is less than 70% of pipe nominal wall thickness the sample size must be expanded. The expansion must include a minimum of the next two most susceptible components in that CHECWORKS line, any component within two diameters downstream (upstream if expander), or like components in parallel trains. If the initial expansion finds additional components with significant loss of material due to FAC, the examination scope is expanded further. If the measured wall thickness is less than T-min, a local thinning evaluation is performed using the methodology of an approved ASME Section XI Code Case. If the component cannot satisfy the local thinning evaluation, it must be replaced or repaired.

Procedures will be enhanced to require a local thinning evaluation if the measured wall thickness is less than T-min.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Flow Accelerated Corrosion Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

A review of plant specific and industry wide operating experience was conducted. There are many instances where components have failed in service due to component wall thinning and rupturing due to erosion. A large number of these failures occurred in two phase systems (saturated steam) where a change in geometry exists. For example: extraction steam line entering a feedwater heater and striking an impingement plate, down stream of a flow control valve, down stream of a flow orifice, down stream of an expander, at 90 degree elbows, etc. Operating experience has also shown failures occurring in single phase systems mostly where a change in geometry exists. For example a condensate line cracked due to localized FAC resulting from bypass-jetting flow around a flow straightener plate in the test metering section of a pipe.

In 1999, Unit 1 experienced a plant shutdown due to steam leaking from feedwater heater 4B. Wall thinning due to steam impingement and flow accelerated corrosion had occurred in the heater shell causing the leak. Inspection of similar Unit 1 feedwater heaters indicated that they required repairs due to wall thinning. Inspection of the Unit 2 feedwater heaters revealed no comparable wall thinning. Root cause analysis of the event also discovered that the materials of construction for the Unit 1 feedwater heaters did not contain a sufficient amount of chromium or molybdenum to help mitigate FAC effects. The original design did not specify for chromium or molybdenum content. Unit 2 feedwater heater materials contain an adequate amount of chromium and molybdenum to mitigate the effects of FAC.

Inspection results are documented in the FAC Outage Report. The report lists each component inspected, its expected remaining life, and the next scheduled inspection. The report also lists work orders initiated to perform required repairs.

The long term PBNP FAC program is continually upgraded based on industry experience and research. This program has provided an effective means of ensuring the structural integrity of high-energy carbon and low alloy steel systems and components.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Flow Accelerated Corrosion Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Flow Accelerated Corrosion Program has been an ongoing program at PBNP since 1987 in response to NRC IEB 87-01. The conservative philosophy established within the program has been successful in managing the loss of material due to FAC. Various sections of the Main and Auxiliary Steam, Feedwater and Condensate, and Auxiliary Feedwater Systems are periodically inspected using nondestructive examinations to determine the effects of FAC. Results are evaluated and components are repaired or replaced as required.

Therefore, the continued implementation of the FAC program provides reasonable assurance that the aging effect of loss of material will be managed such that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.12 Fuel Oil Chemistry Control Program

Program Description

The Fuel Oil Chemistry Control Program mitigates and manages aging effects on the internal surfaces of fuel oil storage tanks and associated components in systems that contain fuel oil. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) periodic or conditional visual inspection of internal surfaces or wall thickness measurements (e.g., by UT) from external surfaces of fuel oil tanks, and (d) one-time inspections of a representative sample of components in systems that contain fuel oil.

The objective of the Fuel Oil Chemistry Control Program is to minimize the introduction and presence of contaminants in the plant's Fuel Oil System that could cause degradation of components in systems that contain fuel oil. This is accomplished by periodic sampling and chemical analysis of the fuel oil inventory at the plant and sampling, testing and analysis of new fuel oil as it is unloaded at the plant. Precautions are also taken during the unloading process to avoid introducing contaminants. Initial samples are visually inspected for entrained foreign material and water. If a sample appears to be unsatisfactory, offloading is discontinued or not allowed. All samples are taken in accordance with ASTM D 4057 and are shipped to a laboratory approved in accordance with the PBNP QA program for analysis. There, the samples are processed by qualified Technicians using approved test equipment and reports are generated and sent back to the plant for review and retention. TRM requirements include the following ASTM standards:

- ASTM D 4057 for sampling,
- ASTM D 2709 for water and sediment analysis,
- ASTM D 6217 for particulate analysis, and
- ASTM D 2274 for stability analysis.

Accumulated water is removed from fuel oil tanks quarterly. The above ground storage tanks are periodically drained and inspected. Day tanks for the Diesel Driven Fire Pump and Emergency Diesel Generators are examined externally via UT wall thickness measurements and the results evaluated against the design thickness. Gas Turbine Starting and Auxiliary Diesel fuel tanks will be drained and inspected prior to the end of the current license. The initial inspection results will be used to determine the periodicity of future inspections. The Emergency Diesel Generator (EDG) below ground storage tanks and the underground emergency fuel tank are drained and inspected if deemed necessary based on the trends indicated by the results of the fuel oil analysis, or as recommended by the System Engineer based on equipment operating experience. Internal tank inspections will identify loss of material due to various aging mechanisms, including general and pitting corrosion and MIC, and may include UT thickness measurements of the tank bottom.

A representative sample of components in systems that contain fuel oil will be inspected for evidence of aging effects via the One-Time Inspection Program and the results documented. These inspections will occur prior to the beginning of the period of extended operation and do not necessarily have to be performed on components that are within the scope of license renewal as long as the environment and material composition of the components inspected are the same as the components within scope.

NUREG-1801 Consistency

The Fuel Oil Chemistry Control Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M30, “Fuel Oil Chemistry” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Preventive Actions
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Acceptance Criteria

Enhancements

Enhancements to the Fuel Oil Chemistry Control Program include revision of existing implementing documents and/or creation of new implementing documents to: periodically drain water from the Gas Turbine Starting and Auxiliary Diesel fuel tanks, periodically drain and inspect the Gas Turbine Starting and Auxiliary Diesel fuel tanks and the two above ground storage tanks, and periodically take UT thickness measurements of the EDG and Diesel Driven Fire Pump day tanks. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Fuel Oil Chemistry Control Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M30, “Fuel Oil Chemistry,” is also provided below.

Scope of Program

The Fuel Oil Chemistry Control Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Emergency Power	Fire Protection

The Fuel Oil Chemistry Control Program mitigates and manages aging effects on the internal surfaces of fuel oil storage tanks and associated components in systems that contain fuel oil. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) periodic or conditional visual inspection of internal surfaces or wall thickness measurements (e.g., by UT) from external surfaces of fuel oil tanks, and (d) one-time inspections of a representative sample of components in systems that contain fuel oil.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

The program is geared to the discovery and correction of conditions that could lead to degradation of fuel oil system components. Accumulated water is periodically removed from the tanks. Draining of accumulated water will also remove sediments from the tanks. The quality of new fuel oil is verified and the quality of stored fuel oil is periodically checked. These actions will mitigate loss of material in the fuel oil tanks and other components. Tank coatings are not credited for the prevention of any aging effects for license renewal.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 discusses the addition of biocides, stabilizers, and corrosion inhibitors. PBNP does not routinely add corrosion inhibitors, stabilizers, or biocides to the fuel oil. PBNP has not experienced oil degradation or MIC that indicates the need for these measures. However, fuel oil additives would be considered if sample results indicate the presence of these degradation mechanisms. NUREG-1801 also states that periodic cleaning of a tank allows removal of sediments. PBNP does not periodically clean fuel oil tanks. Draining and cleaning of tanks would occur if determined to be necessary based on the trends indicated by the results of the fuel oil analysis or as recommended by the System Engineer based on equipment operating experience.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The parameters monitored by the Fuel Oil Chemistry Control Program for the purposes of aging management for license renewal are water, sediment, particulate, and stability. These parameters are included in the requirements of the TRM.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 refers to several ASTM Standards: D 4057 used for guidance on oil sampling, D 1796 and D 2709 used for determination of water and sediment contamination in diesel fuel, and modified D 2276 Method A for determination of particulates. PBNP uses the recommendations and methodology of D 4057 for guidance on oil sampling, and D 2709 to determine the amount of contamination due to water and sediment in diesel fuel. Both tests give results as a percentage of total contaminants. D 1796 adds a solvent to the sample, while D 2709 does not. PBNP uses D 6217 in lieu of D 2276 for particulate determination. The difference between these standards is that D 6217 uses a one liter fuel oil sample size and D 2276 uses a five liter fuel oil sample size and thus takes much longer to perform the test due to the larger amount of particulates that require filtration. D 2276 was developed for aviation fuels and not a middle distillate fuel used in diesel engines, therefore D 6217 is the more appropriate standard to use. PBNP also uses a filter with a pore size no larger than 0.8 micron versus the NUREG-1801 recommendation of 3.0 micron, thus PBNP is more conservative. The level of microbiological organisms in the fuel oil is not directly measured, but can be inferred from the particulate and stability parameters. PBNP uses ASTM D 2274 for stability analysis.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Detection of Aging Effects

The above ground storage tanks are periodically drained and inspected. Day tanks for the Diesel Driven Fire Pump and Emergency Diesel Generators are periodically examined externally via UT wall thickness measurements. Gas Turbine Starting and Auxiliary Diesel fuel tanks will be drained and inspected prior to the end of the current license. The initial inspection results will be used to determine the periodicity of future inspections. The Emergency Diesel Generator below ground storage tanks and the underground emergency fuel tank are drained and inspected if deemed necessary based on the trends indicated by the results of the fuel oil analysis, or as recommended by the System Engineer based on equipment operating experience. Internal tank inspections will identify loss of material due to various aging mechanisms, including general and pitting corrosion and MIC, and may include UT thickness measurements of the tank bottom. The One-Time Inspection Program is credited for the detection of aging effects in other components in systems that contain fuel oil. These inspections provide evidence of the effectiveness of the Fuel Oil Chemistry Control Program to mitigate loss of material in the fuel oil system tanks and other components in systems that contain fuel oil.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The exception is that PBNP does not periodically perform an internal inspection of all of the fuel oil tanks. Day tanks for the Diesel Driven Fire Pump and Emergency Diesel Generators are examined externally via UT wall thickness measurements, which the NUREG-1801 program description describes as an acceptable verification program.

The Emergency Diesel Generator below ground storage tanks and the underground emergency fuel tank are drained and inspected only if deemed necessary based on the trends indicated by the results of the fuel oil analysis, or as recommended by the System Engineer based on equipment operating experience. This is considered acceptable based on the inspection results of the underground emergency fuel tank and the above ground storage tanks which were inspected in 2000 and showed no appreciable material loss in over thirty years of operation. The Emergency Diesel Generator below ground storage tanks are relatively new tanks which were installed in the 1994 time frame and are in a less severe environment than the above ground storage tanks.

Enhancements to the Fuel Oil Chemistry Control Program will include procedure revisions and/or the creation of other implementing documents to include the following:

- periodically drain water from the Gas Turbine Starting and Auxiliary Diesel fuel tanks,
- periodically drain and inspect the Gas Turbine Starting and Auxiliary Diesel fuel tanks and the two above ground storage tanks, and
- periodically take UT thickness measurements of the EDG and Diesel Driven Fire Pump day tanks.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

The monitoring and trending requirements for all parameters controlled by the Fuel Oil Chemistry Control Program are included in the TRM and plant procedures. Sampling techniques, periodicity, and sample size are clearly defined in these procedures. The parameters monitored include water, sediment, particulate, and stability. These parameters are measured and trended quarterly. The level of microbiological organisms in the fuel oil is inferred from the particulate and stability parameters.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

The acceptance criteria for the fuel oil parameters required to be monitored and controlled are listed in the TRM. As previously stated, PBNP uses the following ASTM Standards as guidance for fuel oil testing and sampling collections: D 4057 for oil sampling, D 2709 for determining water and sediment contamination, D 6217 for determining particulate contamination, and D 2274 for determining fuel oil stability. Tank bottom plate thickness measurements will be evaluated against the design thickness.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. PBNP deviates from some of the testing methodology detailed in NUREG-1801. PBNP does not use ASTM Standard D 1796 for water and sediment and does not use D 2276 for particulate. The other exception is that PBNP uses a filter pore size of 0.8 micron and not the 3.0 micron specified in the NUREG-1801 element. PBNP uses the guidance provided in ASTM Standards D 4057, D2709, D 6217, and D 2274.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Fuel Oil Chemistry Control Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

The operating experience of some plants has included identification of water in the fuel, particulate contamination, and biological fouling. A search of plant-specific operating experience has revealed past problems with sampling methods, which were corrected with a revision to the sampling procedure. Problems were also noted with the particulate levels of delivered fuel oil and were attributed to the fuel oil cloud point and cold weather. QA audits performed on the laboratory that performs the analysis of the fuel oil samples indicate that the laboratory is performing satisfactorily. The internals of the above ground fuel oil tanks and the underground emergency fuel tank were inspected in August of 2000 and no significant rust deposits, corrosion, or other obvious defects were found. Thickness measurements of the underground emergency fuel tank and the bottom of the above ground fuel oil tanks were performed and indicated no significant loss of material. There have been no identified instances of component failure due to loss of material resulting from fuel oil contamination.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Fuel Oil Chemistry Control Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Fuel Oil Chemistry Control Program provides reasonable assurance that aging effects will be managed such that systems and components within the scope of license renewal will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation. The Fuel Oil Chemistry Control Program has been an ongoing, evolving program at the plant since initial startup. This program relies on periodic sampling and analysis to verify that the quality of the fuel oil in the storage tanks is being maintained within the parameters specified in the TRM. The Fuel Oil Chemistry Control Program provides assurance that the fluid environment to which tanks, piping, and associated components are exposed will minimize corrosion and selective leaching. This is accomplished through effective monitoring of key parameters at established frequencies and with well-defined acceptance criteria. Fuel oil chemistry data is monitored for trends that might be indicative of an underlying problem. This will provide for early detection of conditions which might adversely affect component intended function(s). Water is also periodically drained from fuel oil tanks and inspections are performed to verify the fluid environment mitigates loss of material of fuel oil tanks and components in systems that contain fuel oil.

The overall effectiveness of the Fuel Oil Chemistry Control Program is supported by the operating experience of systems and components which are influenced by the program. There have been no identified instances of component failure due to loss of material resulting from fuel oil contamination. In addition, the internals of the above ground fuel oil tanks and the underground emergency fuel tank were inspected in August of 2000 and no significant degradation was found.

B2.1.13 One-Time Inspection Program

Program Description

The One-Time Inspection Program addresses potentially long incubation periods for certain aging effects and provides a means of verifying that an aging effect is either not occurring or progressing so slowly as to have negligible effect on the intended function of the structure or component. Hence, the One-Time Inspection Program provides measures for verifying an aging management program is not needed, verifying the effectiveness of an existing program, or determining that degradation is occurring which will require evaluation and corrective action.

The program elements include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The inspection sample includes locations where the most severe aging effect(s) would be expected to occur. Inspection methods may include visual (or remote visual), surface or volumetric examinations, or other established NDE techniques.

This program is used for the following:

- To verify the effectiveness of water chemistry control for managing the effects of aging in stagnant or low-flow portions of piping, or occluded areas of components, exposed to a treated water environment.
- To manage the aging effects of loss of material due to galvanic corrosion and selective leaching
- To manage aging effects in infrequently accessed areas, such as high radiation, high temperature, confined spaces, and submerged areas.
- To verify the effectiveness of fuel oil chemistry control for managing the effects of aging of various components in systems that contain fuel oil.
- To verify aging effects are not occurring in various components (e.g., reactor vessel internals hold-down spring, letdown orifices, steam traps, and miscellaneous heat exchangers).

To verify the effectiveness of water chemistry control, this program will perform a one-time inspection on selected components where the flow of water is low or stagnant conditions exist. To verify the effectiveness of fuel oil chemistry control, this program will inspect various components in systems that contain fuel oil. The components to be inspected shall be chosen from the various systems within the scope of the Water Chemistry Control Program, the Closed-Cycle Cooling Water System Surveillance Program, and the

Fuel Oil Chemistry Control Program. For systems that contain fuel oil, these inspections do not necessarily have to be performed on components that are within the scope of license renewal as long as the environment and material composition of the components inspected are the same as the components within scope. From these lists of components, a sample of the population will be selected for inspection as part of the One-Time Inspection Program. The inspection population will be based on such aspects of the SSCs as similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects. The sample size will be based on such aspects of the SSCs as the specific aging effect, location, existing technical information, system and structure design, materials of construction, service environment, or previous failure history. The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation. The inspection requirements may be satisfied by a destructive examination of removed components or a review of repair records to confirm that the component has been inspected for aging degradation and no significant degradation has occurred.

This program will perform an inspection for evidence of stress relaxation in the reactor vessel hold-down spring by performing a measurement of the non-compressed spring height. The inspection will be performed prior to the beginning of extended operation and the results will be evaluated against design specifications to determine if any corrective actions need to be taken to ensure adequate spring force will be maintained through the period of extended operation.

This program also assesses the loss of material due to galvanic corrosion on the internal surfaces of susceptible components. This program will select the locations to be inspected, provide the inspection criteria, evaluate the results of the inspections and provide recommendations for additional inspections, as necessary. The susceptibility and aggressiveness of galvanic corrosion is determined by the material position on the galvanic series, the conductivity of the surrounding environment and the ratio of the cathode to anode areas. Thus an inspection of selected locations of dissimilar metal connections in the systems for PBNP will determine whether loss of material due to galvanic corrosion will be an aging effect of concern for the period of extended operation. The results of these inspections will be indicative of material couples such as carbon steel-stainless steel, carbon steel-copper alloy, and copper alloy-stainless steel connections, or others used throughout the systems at PBNP, and they will also determine the need for additional inspections to manage this aging effect. Visual or volumetric examinations will be used to verify whether galvanic corrosion is a concern at PBNP. Any corrective actions will be implemented through the corrective action program.

The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation. The inspection requirements may be satisfied by a review of repair or other inspection records to confirm that the component has been inspected for aging degradation and no significant degradation has occurred.

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The most common example is the selective removal of zinc in brass alloys (dezincification). Another metal that is susceptible to selective leaching is gray cast iron, which can display this type of aging mechanism even in relatively mild environments. Therefore, this program includes a one-time visual inspection of selected components that may be susceptible to selective leaching. The inspection may include hardness measurements. The one-time inspections will determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function(s) for the period of extended operation. A sample of the components (such as piping, valve bodies and bonnets, pump casings, and heat exchanger components), whose materials of construction may include cast iron, brass, bronze, or aluminum bronze, that are exposed to raw water, treated water, or ground water environment that may lead to selective leaching will be selected for inspection. The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation. Any corrective actions will be implemented through the corrective action program.

NUREG-1801 Consistency

The One-Time Inspection Program is a new program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M33, “Selective Leaching of Materials,” and Section XI.M32, “One-Time Inspection” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 program element assumptions:

- Scope of Program
- Parameters Monitored or Inspected
- Detection of Aging Effects

Enhancements

The One-Time Inspection Program is a new program. Enhancements to the program include the creation of new implementing documents required to provide those inspections necessary to manage aging of components within the scope of license renewal. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the One-Time Inspection Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.M32, “One-Time Inspection,” and XI.M33, “Selective Leaching of Materials,” is also provided below.

Scope of Program

The One-Time Inspection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Fire Protection
Chemical and Volume Control	Heating Steam
Class 1 Piping/Components	Main and Auxiliary Steam
Component Cooling Water	Non-Class 1 RCS Components
Containment Isolation Components	Residual Heat Removal
Containment Spray	Safety Injection
Emergency Power	Spent Fuel Cooling
Essential Ventilation	Treated Water
Feedwater and Condensate	Waste Disposal

The One-Time Inspection Program will be used to determine the acceptability of components that may be susceptible to various aging effects and to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of an existing aging management program or confirming that there is no need to manage age-related degradation for the period of extended operation. For selective leaching, which is a slow acting corrosion process, visual examinations are performed to verify that this aging mechanism is not occurring. Hardness measurements may also be performed to identify selective leaching. The scope of this program includes the following:

- Verification of the effectiveness of the Water Chemistry Control Program for managing the effects of aging in stagnant or low flow portions of piping, or occluded areas of components, exposed to a treated water environment.
- Management of the aging effect loss of material due to galvanic corrosion and selective leaching.
- Verification of the effectiveness of the Closed-Cycle Cooling Water System Surveillance Program for managing the effects of aging in selected heat exchangers and stagnant or low flow portions of closed-cycle systems.
- Management of aging effects in infrequently accessed areas, such as high radiation, high temperature, confined spaces, and submerged areas.
- Verification of the effectiveness of the Fuel Oil Chemistry Control Program for managing the effects of aging of various components in systems containing fuel oil.
- Verification that aging effects are not occurring in various components (e.g., reactor vessel internals hold-down spring, letdown orifices, steam traps, and miscellaneous heat exchangers).

This element includes exceptions to the corresponding NUREG-1801, Section XI.M33, “Selective Leaching of Materials” aging management program element. Section XI.M33 of NUREG-1801 states that hardness measurements are performed on a select set of components. The internal surfaces of susceptible components may not be accessible for hardness measurements due to the size of the component. Therefore, only visual inspections are required by the program. Hardness measurements may be performed in accessible locations to confirm the absence of selective leaching and determine material properties which can be used in component functionality assessments.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M32, “One-Time Inspection,” aging management program element. Section XI.M32 of NUREG-1801 lists small bore piping in the reactor coolant system as an example of components included in the program. Examination of non-exempt small bore ASME Class 1 and 2 piping at PBNP will be addressed within the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, which includes volumetric examinations performed in accordance with Risk-Informed Inservice Inspection (RI-ISI) requirements.

Enhancements to the program include the creation of new implementing documents required to provide those inspections necessary to manage aging of components within the scope of license renewal.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Preventive Actions

The one-time inspection activities conducted as part of this program are independent of methods to mitigate or prevent degradation. However, it is noted that for those systems where fluid chemistry is controlled and monitored, this inspection will verify that fluid chemistry is effective in mitigating the applicable aging effects.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Parameters Monitored or Inspected

For verification of the effectiveness of the Water Chemistry Control Program and the Closed-Cycle Cooling Water System Surveillance Program for stagnant or low flow areas and for verification of the effectiveness of the Fuel Oil Chemistry Control Program, a visual examination or other appropriate NDE methodology will be used to verify that degradation due to the applicable aging effects is not occurring. For selective leaching, which is a slow acting corrosion process, visual examinations will be performed to verify that this aging mechanism is not occurring. Hardness measurements may also be performed to confirm the absence of selective leaching. For verification that galvanic corrosion on the internal surfaces of piping and components where galvanic couples are present is not occurring, visual (or remote visual) or volumetric examinations will be performed. Measurement of the non-compressed spring height will be used to detect evidence of stress relaxation in the reactor vessel hold-down spring.

This element is consistent with the corresponding NUREG-1801, Section XI.M32, “One-Time Inspection,” aging management program element.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M33, “Selective Leaching of Materials,” aging management program element. Section XI.M33 of NUREG-1801 states that hardness measurements are performed on a select set of components. The internal surfaces of susceptible components may not be accessible for hardness measurements due to the size of the component. Therefore, only visual inspections are required by the program. Hardness measurements may be performed in accessible locations to confirm the absence of selective leaching and determine material properties which can be used in component functionality assessments.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Detection of Aging Effects

The examination techniques will be visual, volumetric, or other appropriately established NDE methods. The NDE will be performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” A representative sample of the component population will be chosen for inspection. The focus, when practical, will be placed on bounding or lead components. Factors that will be considered when choosing components for inspection are time in service, severity of operating conditions, and operating experience.

Visual examinations will be used to detect selective leaching. In addition, hardness measurements may be taken to determine whether selective leaching has occurred and whether the resulting loss of strength and/or material will affect the intended function of the components during the period of extended operation. To detect loss of material due to galvanic corrosion, visual (or remote visual) or volumetric examinations will be used. The loss of material will be evident at the location of the junction of the dissimilar metals.

To verify that the Water Chemistry Control Program and the Closed-Cycle Cooling Water System Surveillance Program are mitigating the applicable aging effects in stagnant or low flow areas, visual examinations or other appropriate NDE methodology will be used when components are inspected.

This program will perform an inspection for evidence of stress relaxation in the reactor vessel hold-down spring by performing a measurement of the non-compressed spring height. The inspection results will be evaluated against design specifications to determine if any corrective actions need to be taken to ensure adequate spring force will be maintained through the period of extended operation.

These one-time inspections will be performed to detect various aging effects prior to entering the period of extended operation. They will be conducted at such times and ways as to minimize the impact on plant operations. The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the period of extended operation. The inspection requirements may be satisfied by a review of repair or other inspection records to confirm that the component has been inspected for aging degradation and no significant degradation has occurred.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M33, “Selective Leaching of Materials,” aging management program element. Section XI.M33 of NUREG-1801 states that hardness measurements are performed on a select set of components. The internal surfaces of susceptible components may not be accessible for hardness measurements due to the size of the component. Therefore, only visual inspections are required by the One-Time Inspection Program. Hardness measurements may be performed in accessible locations to confirm the absence of selective leaching and determine material properties which can be used in component functionality assessments.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M32, “One-Time Inspection,” aging management program element. Section XI.M32 of NUREG-1801 references Information Notice (IN) 97-46 for determining the inspection locations of small bore piping. Section XI.M32 of NUREG-1801 also requires plant-specific destructive examination of replaced piping due to plant modifications, or NDE that will detect cracking on the inside surfaces of the small bore piping. Examination of small bore, non-exempt ASME Class 1 and 2 piping at PBNP will be addressed within the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, which includes volumetric examinations performed in accordance with Risk-Informed Inservice Inspection (RI-ISI) requirements.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Monitoring and Trending

This new One-Time Inspection Program does not provide for monitoring and trending. However, follow up examinations will be required if unacceptable conditions are discovered, thus expanding the sample size and locations of inspections.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Acceptance Criteria

Any indications of degradation or unacceptable conditions are evaluated through the corrective action program. The need to increase the sample population will also be evaluated when indications or relevant conditions of degradation are found.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Administrative Controls

The One-Time Inspection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Operating Experience

The One-Time Inspection Program is a new program to be implemented before the current operating license expires. The NDE inspection methods that will be used, such as visual (or remote visual), surface or volumetric, or other established techniques, are consistent with industry practice.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Conclusion

The implementation of the One-Time Inspection Program will provide reasonable assurance that the applicable aging effects will be discovered such that the systems and components that credit this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. The One-Time Inspection Program is a new program used to verify that aging effects are either not occurring or, if they are occurring, progressing at such a slow rate that they will not affect the intended function(s) of the components for the period of extended operation. The program will use techniques with demonstrated capability and a proven industry record to detect the applicable aging effects. The one-time inspections will be performed utilizing approved plant procedures and qualified personnel.

B2.1.14 Open-Cycle Cooling (Service) Water System Surveillance Program

Program Description

The Open-Cycle Cooling (Service) Water System Surveillance Program manages aging effects caused by exposure of internal surfaces of metallic components in water systems (e.g., piping, valves, heat exchangers) to raw, untreated (e.g., service) water. The aging effects are managed through (a) surveillance and control of biofouling, (b) verification of heat transfer by testing, and (c) routine inspection and maintenance program activities to ensure that aging effects do not impair component intended function. Inspection methods include visual, ultrasonic (UT), eddy current (ECT), and Tangential Radiography. This program complies with PBNP’s response to NRC GL 89-13.

The Open-Cycle Cooling (Service) Water System Surveillance Program is credited for managing aging effects such as loss of material due to general, pitting, and crevice corrosion, MIC, and loss of heat transfer due to biological/corrosion product fouling (e.g., sedimentation, silting) caused by exposure of internal surfaces of metallic components in cooling water systems (e.g., piping, valves, heat exchangers) to raw, untreated (e.g., service) water. PBNP uses Tangential Radiography as the primary method of examination to detect pipe degradation. Tangential Radiography was selected as the primary method of inspection over other NDE techniques because it provides the ability to detect all the effects of concern with one examination technique. These include the ability to inspect both insulated and bare piping and valves for internal degradation due to corrosion by nodule growth, cavitation, and erosion; the ability to inspect insulated piping and valves for exterior corrosion; and the ability to inspect piping for flow blockage due to sedimentation, silt, and nodule growth. Augmented examinations using other techniques such as ultrasonic, visual or remote visual inspection methods are also implemented when necessary to complement radiography. UT is a very localized NDE technique that provides precise wall thickness measurements and pipe degradation can be mapped very accurately. Visual inspections of equipment and components are an essential part of the program.

Biofouling control is accomplished by the addition of chlorine to the systems that are exposed to Lake Michigan water, periodic mechanical removal of zebra mussels, and periodic chemical treatment for zebra mussel control. The primary method for microfouling control is operation of the chlorination system. The concentration of the chemical is adjusted based on evaluations of microfouling evidence. Periodic injection of the biocide EVAC has been used to eliminate zebra mussels from the affected systems. This process is intended to kill adult Zebra Mussels. The EVAC treatment was placed on standby and replaced with a continuous copper ion generator treatment. The effectiveness of the new treatment will be monitored and the decision whether to abandon the EVAC treatment will be made in the future after inspection results are available.

The preferred method of cleaning heat exchanger tubes is hydro lancing and the NDE method most used is Eddy Current Testing (ECT). The inspections are used to track the condition of the equipment exposed to raw water and the effectiveness of the Biofouling control methods. In addition, the ECT results are used to predict the remaining life of the tubes so that proper steps can be taken to ensure that heat exchangers will continue to perform their intended functions. GL 89-13 commitments include the performance testing of selected heat exchangers.

Some of the in-scope components in the Service Water System that are not frequently operated are periodically flushed to control sediment build-up, preferably during the chlorination treatments, whenever possible.

NUREG-1801 Consistency

The Open-Cycle Cooling (Service) Water System Surveillance Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M20, “Open-Cycle Cooling Water System” (Reference 3).

Exceptions to NUREG-1801

See the following element discussion for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program

Enhancements

Enhancements to the Open-Cycle Cooling (Service) Water System Surveillance Program include: verification that the implementing documents for activities credited by the plant's “GL 89-13 Program Document” contain a reference or other link back to the “GL 89-13 Program Document,” clarification of GL 89-13 commitments regarding the Emergency Diesel Generator G01/G02 coolant heat exchangers, revisions to existing callups to ensure evaluations take place for the management of aging effects credited by the activity for license renewal, and the creation of new activities to inspect individual components or representative samples of components not addressed by existing activities. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Open-Cycle Cooling (Service) Water System Surveillance Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M20, “Open- Cycle Cooling Water System,” is also provided below.

Scope of Program

The Open-Cycle Cooling (Service) Water System Surveillance Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Essential Ventilation
Component Cooling Water	Service Water
Containment Ventilation	Spent Fuel Cooling
Emergency Power	

The purpose of the Open-Cycle Cooling (Service) Water System Surveillance Program is to perform periodic inspections and/or tests to detect degradation, monitor system integrity, and perform evaluations required to maintain reliability and operability of systems and components within its scope. This is accomplished by following the guidelines provided in GL 89-13, which include (a) surveillance and control of biofouling, (b) verification of heat transfer by testing, and (c) routine inspection and maintenance program activities to ensure that aging effects do not impair component intended function.

GL 89-13 also required a system walkdown inspection to ensure compliance with the licensing basis and a review of maintenance, operating, and training practices and procedures. These requirements were satisfied as part of the response to the generic letter and are discussed in the PBNP “GL 89-13 Program Document.” These requirements are not associated with the management of aging effects and there are no corresponding activities in the Open-Cycle Cooling (Service) Water System Surveillance Program.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. Not all of the safety related heat exchangers are tested to verify heat transfer capability by performing a heat balance test. The Primary Auxiliary Building Battery Room Vent Coolers, Turbine Driven Auxiliary Feed Water Pump turbine oil coolers, Containment Fan motor coolers, and Emergency Diesel Generators G01/G02 coolant heat exchangers, are not routinely tested to verify heat transfer capability. As described in the PBNP “GL 89-13 Program Document,” an acceptable alternative to testing that can be applied to small heat exchangers is frequent regular maintenance. These components are periodically flushed or cleaned and inspected as described in Appendix C of the PBNP “GL 89-13 Program Document” and/or the PBNP HX-01, “Heat Exchanger Condition Assessment Program.” The “D” Containment

Accident Fan heat exchangers in each unit are periodically performance tested and are considered to be representative of the other accident fan heat exchangers.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

Periodic operation of the chlorination system and/or the new copper ion generator treatments are methods used to control MIC and biofouling such as zebra mussel growth. Flushing of infrequently used components removes accumulation of biofouling agents, corrosion products, and silt.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The parameters monitored, inspected, or tested vary depending on the component and are based on operating experience. Some heat exchangers are visually inspected, some are inspected to verify that service water is flowing through the coolers, and some are tested for heat transfer capability. Pressure drop across some components is measured and trended, while some components are periodically cleaned and inspected.

Various actions are undertaken to verify system or component performance will not be compromised, which can be adversely affected by the accumulation of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers, and their coatings are periodically inspected, monitored, or tested to ensure heat transfer capabilities. The program ensures (a) removal of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded piping and components that could adversely affect the performance of their intended safety function. The activities performed under this program address the concerns described in GL 89-13 and their continued performance will ensure that the Service Water System will continue to perform its intended function.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

The PBNP “Service Water In-Service Inspection Program” implements GL 89-13 requirements for establishing a routine inspection and maintenance program for Service Water System piping and components such that corrosion, erosion, protective coating failure, silting, and biofouling do not degrade the performance of the safety related systems supplied by service water. The inspection program verifies that the system will perform its design basis heat removal function by ensuring that sufficient water flow is maintained.

To detect and measure sediment build-up, MIC, pitting, general corrosion, and exterior pipe corrosion, PBNP uses Tangential Radiography as the primary method of examination. UT and visual inspections are used when necessary to augment the radiography examinations. The initial representative examinations were based on approximately ten percent of the total piping length. Subsequent examinations are based on inspection results, equipment performance, system requirements, and recommendations from Operations, Maintenance, and Engineering. Portions of piping are impractical to examine. In this case, supportive evidence is developed to demonstrate the status of the component's integrity or that the piping has not been degraded. For example, the service water underground piping from the circulating water pump house to the turbine hall is inaccessible and impractical to examine. This piping was declared exempt from examination, since radiography of the accessible and bounding pipe sections show minimal signs of degradation.

The examination locations are chosen based on the following problem areas and plant operating experience. For biofouling: stagnant lines or low flow lines (areas with less than 1 fps) or intermittent flow lines where nutrients are periodically introduced. For sedimentation: horizontal low flow lines, stagnant dead legs, bypass lines or cross connecting lines. For cavitation/erosion damage: downstream of throttle valves and orifices, in locations where the return header drops to vacuum, and other areas of high velocity.

Heat exchangers are cleaned and ECT of a sample of tubes is performed to detect tube degradation. In addition, some heat exchangers are tested for their heat transfer capability.

The frequency and scope of inspections vary with the component's location, system flow rate, past history and calculated life remaining based on the guidelines in the PBNP “Service Water In-Service Inspection Program” and the PBNP HX-01, “Heat Exchanger Condition Assessment Program.”

Enhancements to plant documents will be made to ensure that the implementing documents and callups for the activities specified in the PBNP “GL 89-13 Program Document” are linked back to the PBNP “GL 89-13 Program Document” by a purpose statement or other reference, clarify the PBNP GL 89-13 commitments regarding the Emergency Diesel Generator G01/G02 coolant heat exchangers, and to ensure evaluations take place for the management of aging effects credited for license renewal.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

The scope of inspections and heat transfer testing are in accordance with PBNP commitments under GL 89-13. In addition, pressure drop across certain components is monitored and trended to detect biofouling or silt accumulation. Other components have the service water flow checked and/or are flushed to reduce biofouling or sedimentation build-up. Component degradation, such as pipe wall thinning and silt build-up, is measured and recorded to predict the expected remaining life of the component such that corrective actions can be taken prior to a loss of intended function. The methodology for the frequency of examinations, locations of examinations, analysis of inspection or test results, and acceptance criteria is specified in the procedures under which such inspections or tests are conducted.

Therefore, inspections and non-destructive testing will determine the extent of MIC and biofouling, the condition of any surface coating, the extent of corrosion, and amount of blockage due to silting. Heat transfer results are documented in plant procedures and are trended and reviewed by the appropriate engineering group.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

The acceptance criteria are specified in the procedures that control the inspections of components. Pipe and tubing wall thickness is measured and compared to minimum required wall thickness. Biofouling is removed or reduced as part of the activities performed under this program. Acceptance criteria are based on maintaining the system free of significant sediment build-up and able to perform its intended functions. The acceptance criteria are also defined in

PBNP “GL 89-13 Program Document.” Performance indicators provide information on whether the ongoing activities meet the intent of the GL 89-13 recommended actions and therefore the objectives of this program. The indicators are: (1) Biofouling Control, (2) Erosion/Corrosion Control, (3) Flow Blockage Control, and (4) Program Implementation (the program effectiveness is routinely checked through periodic reviews). The procedures used for performance testing of the “D” Containment Fan Coolers, Component Cooling Water heat exchangers, and Spent Fuel Pool heat exchangers provide the applicable acceptance criteria.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Open-Cycle Cooling (Service) Water System Surveillance Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

Heat exchangers have experienced erosion/corrosion of end bells, biofouling build-up, and silt accumulation. Erosion/corrosion has also been experienced at or near throttled valves. Zebra mussels have been found and are controlled by the chlorination system, copper ion generator treatment, and periodic cleaning of the heat exchanger tubes. Piping systems have experienced corrosion, pitting, MIC, and sedimentation build-up especially in low flow areas and stagnant dead legs off the main flow stream. These are controlled by flushing, the chlorination system, and inspections. Cavitation/erosion of components is monitored by using established NDE methods and components have been repaired/replaced, as necessary.

Plant-specific operating experience was reviewed and revealed that Condition Reports (Action Requests) and Work Orders were initiated to repair system leaks and/or to investigate component wall thinning due to corrosion. Descriptions of some of the typical deficiencies found in Service Water System components and addressed via the corrective action program are provided below.

- Both A & B Component Cooling Water heat exchangers experienced corrosion in the wall and nozzle area of the outlet channel head.
- Localized pitting was found in the Service Water piping supply to the old Spent Fuel Pool heat exchanger. UT examination revealed that 68% wall thinning had occurred and silt was found in the pipe.
- Leakage was found in the Component Cooling Water heat exchanger blowdown lines.
- Deep pitting due to MIC was found on the G01 Diesel Generator heat exchangers. The pitting occurred beneath deposits formed by iron oxidizing bacteria. G02 coolers were inspected and did not have a similar problem due to the protective epoxy coating.
- Radiography of the K-3A Service Water Air Compressor After Cooler heat exchanger showed significant wall thinning due to internal corrosion. The heat exchanger also exhibited blockage due to nodule buildup.
- The G01 Diesel Generator heat exchangers (HX-55A-2 and HX -55A-1) were found to have significant erosion/corrosion at the south end bells.
- Spent Fuel Pool heat exchanger HX-13A outlet valve body was found to be severely pitted and eroded.

These examples show that the program in place at PBNP is discovering and correcting deficiencies before they impede the component's intended function.

The guidance of GL 89-13 has been implemented for approximately 10 years and has been effective in managing and monitoring the aging effects due to biofouling, corrosion, erosion, degradation of protective coatings, and silting in components serviced by the Service Water System.

A corrective action document was written requesting review of PBNP's GL 89-13 commitments pertaining to the Emergency Diesel Generators G01/G02 coolant heat exchangers. This issue is being tracked under the corrective action program.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no other issues or findings that could impact the effectiveness of the Open-Cycle Cooling (Service) Water System Surveillance Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Open-Cycle Cooling (Service) Water System Surveillance Program provides reasonable assurance that the Service Water System components will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation. The Open-Cycle Cooling (Service) Water System Surveillance Program follows the guidelines of GL 89-13. It uses various methods to ensure that the Service Water System will continue to perform its intended function. Tangential Radiography is used to detect pipe wall loss, component silt build-up, and biofouling. Augmented examinations using other techniques such as ultrasonic, visual or remote visual inspection methods are also implemented when necessary to complement radiography. Tangential Radiography and UT are used to measure the remaining wall thickness of components. Pressure drop measurements are used to detect fouling build-up between sections of pipe or across components. Flushing of components is used to remove sediment and biofouling build-up. Thermal performance testing of selected heat exchangers is used to verify that they can continue to perform their heat removal intended function. The use of the chlorination system and/or copper ion generator treatments limit the growth of zebra mussels and biofouling. Periodic heat exchanger tube cleaning and ECT verifies that the heat exchangers are able to perform their intended function(s) by monitoring the degradation of the heat exchangers tubes and performing repairs or replacement, as necessary.

B2.1.15 Periodic Surveillance and Preventive Maintenance Program

Program Description

The Periodic Surveillance and Preventive Maintenance Program is an existing plant-specific program that manages aging effects for certain SSCs within the scope of license renewal. The program provides for inspection, examination, or testing of selected structures and components, including fasteners, for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or code requirements). Additionally, the program provides for replacement of certain components on a specified frequency based on operating experience. The Periodic Surveillance and Preventive Maintenance Program is also used to verify the effectiveness of other aging management programs.

It should be noted that surveillance and preventive maintenance activities associated with another aging management program are evaluated and identified as an implementing document as part of that program. However, they are also subject to the applicable requirements and controls of the Periodic Surveillance and Preventive Maintenance Program, including the constraints placed on deferrals, cancellations, and frequency changes.

Various surveillance and preventive maintenance activities are relied on to replace or manage the age-related degradation of structures and components within the scope of license renewal. The frequency of these predefined/recurring surveillance and preventive maintenance activities are specified by callups maintained in the Computerized History and Maintenance Planning System (CHAMPS). CHAMPS is a computer based program in which records of work performed on plant SSCs are initiated and managed. (It should be noted that CHAMPS is scheduled for replacement with a similar maintenance management system called EMPAC.)

Individual surveillance and preventive maintenance Work Orders for callups performed at regular intervals are forecast in CHAMPS from the controlled master callup files to support the long range scheduling of these requirements. Work Orders are records created in CHAMPS to assign, manage, track the status, and identify the scope of work. The work scope is identified directly by the callup or through reference to applicable Work Plans, drawings and approved procedures. Work Plans provide a formatted description of the work scope to be performed in implementing an activity.

Enhancements

Enhancements to the Periodic Surveillance and Preventive Maintenance Program include both the creation of new and revisions to existing implementing documents to perform the necessary inspection, examination, or testing activities required to manage aging of selected structures and components within the scope of license renewal. The high level program documents will be enhanced to improve program documentation, ensure program elements are factored into the applicable surveillance and preventive maintenance activities credited for license renewal, place additional requirements and controls on activities credited for license renewal, including constraints on deferrals, cancellations, and frequency changes, and to ensure the initiation of an Action Request whenever the acceptance criteria is not met or if the activity is not completed within its allowed grace period, unless the activity has been properly deferred or cancelled. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Periodic Surveillance and Preventive Maintenance Program, are described below. An evaluation of each key element against the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” was conducted.

Scope of Program

The Periodic Surveillance and Preventive Maintenance Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Plant Air
Circulating Water	Pressurizer
Containment Unit 1/2 Building Structure	Primary Auxiliary Building Structure
Containment Ventilation	Residual Heat Removal
Emergency Power	Service Water
Essential Ventilation	Steam Generator
Main and Auxiliary Steam	Waste Disposal
Non-Class 1 RCS Components	

The Periodic Surveillance and Preventive Maintenance Program manages aging effects for certain SSCs within the scope of license renewal. The program provides for inspection, examination, or testing of selected structures and components, including fasteners, for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or code requirements). Additionally, the program provides for replacement of certain components on a specified frequency based on operating experience. The Periodic Surveillance and Preventive Maintenance Program is also used to verify the effectiveness of other aging management programs.

Preventive Actions

There are no preventive measures associated with the aging effects of concern for license renewal. The inspection, examination, or testing of selected structures and components on a specified frequency is intended to identify the extent to which aging effects are occurring (i.e., condition). The replacement of certain components on a specified frequency also does not prevent aging effects from occurring. Aging effects are mitigated by periodically replacing components on a specified interval to prevent age-related degradation leading to a loss of intended function.

Parameters Monitored or Inspected

The condition of selected structures and components is monitored through inspection, examination, or testing for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or code requirements). Certain components are also replaced on a given frequency based on operating experience.

Detection of Aging Effects

The aging effects of concern are detected by inspection, examination, or testing of selected structures and components. Certain components are also replaced on a given frequency based on operating experience.

The periodicity of most surveillance and preventive maintenance activities that are credited for license renewal is usually driven by considerations other than aging, since the effects of aging usually occur slowly over time. For example, a check valve internal inspection is more likely to be driven by seat/disc/hinge pin wear than by erosion or corrosion of the valve body and the periodicity of most surveillance activities is based on plant Technical Specification requirements.

Activities credited for license renewal are subject to the constraints described below regarding frequency changes, deferrals, and cancellations, and plant procedures will be revised accordingly to ensure that these requirements are met.

Surveillance and preventative maintenance activities credited for license renewal shall be completed within a grace period of 125% of their assigned interval, not to exceed 2 years. The frequency of surveillance and preventive maintenance activities that are credited for license renewal may be adjusted, or the activity deferred or canceled provided an evaluation is performed justifying the change from a license renewal perspective based on plant and industry operating experience. An Action Request will be initiated for any surveillance or preventive maintenance activity credited for license renewal that is not completed within its allowed grace period, unless the activity has been properly deferred or cancelled.

Additional procedure changes shall be accomplished to include the following:

- Surveillance and preventive maintenance activities credited for license renewal shall be performed on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or code requirements).
- The results of surveillance and preventive maintenance activities credited for license renewal shall be documented, and subject to review and approval.
- Surveillance and preventive maintenance activities credited for license renewal shall be specified by callups maintained in the equipment database, flagged as license renewal commitments, and subject to additional requirements and controls, including the constraints placed on deferrals, cancellations and frequency changes for license renewal.

Monitoring and Trending

Inspection, examination, testing, and component replacement activities credited for license renewal are performed on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or code requirements). The results of these surveillance and preventive maintenance activities are documented, and subject to review and approval.

Acceptance Criteria

Acceptance criteria for inspection, examination, or testing of selected structures and components for evidence of age-related degradation are provided in the surveillance and preventive maintenance activities credited for license renewal. The acceptance criteria are related to the aging effect(s) of concern and are tailored to each individual inspection, examination, or test considering the aging effect(s) being managed. An Action Request will be initiated whenever the acceptance criteria are not met. Certain components are also replaced on a given frequency based on operating experience.

Plant procedures shall be revised to include the following:

- Acceptance criteria shall be specified in the surveillance and preventive maintenance activities credited for license renewal aging management. The acceptance criteria shall be related to the aging effect(s) of concern and tailored to each individual inspection, examination, or test considering the aging effect(s) being managed.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

Administrative Controls

The Periodic Surveillance and Preventive Maintenance Program is implemented through various plant administrative procedures. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

Operating Experience

The Periodic Surveillance and Preventive Maintenance Program has been effective in maintaining the intended functions of long-lived passive SSCs. Surveillance and preventive maintenance activities entered in CHAMPS are effectively managed, with an improving trend noted in internal and external assessments performed over the past several years. Numerous Condition Reports, Action Requests, and Work Orders have been generated and resolved through the implementation of this program, which demonstrates the effectiveness of this program to identify and correct age-related degradation prior to a loss of intended function.

NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 were reviewed to determine the effectiveness of the Periodic Surveillance and Preventive Maintenance Program. A number of process and procedural weaknesses were identified and upgrade efforts were undertaken to improve the overall effectiveness of the Periodic Surveillance and Preventive Maintenance Program. The backlog of over due preventive maintenance activities was excessive at one time, but has since been significantly reduced. A QA Audit noted that the preventive maintenance activities presently in CHAMPS were found to be effectively implemented as scheduled. Additional program improvements have also been initiated.

Conclusion

The Periodic Surveillance and Preventive Maintenance Program is an established program at PBNP, that has been effective in maintaining the intended functions of long-lived passive SSCs. Surveillance and preventive maintenance activities entered in CHAMPS are effectively managed, with an improving trend noted in internal and external assessments performed over the past several years. Activities credited for license renewal will be specified by callups maintained in CHAMPS, flagged as license renewal commitments, and subject to additional requirements and controls, including the constraints placed on deferrals, cancellations, and frequency changes for license renewal. Therefore, there is reasonable assurance that the aging effects of concern will be managed by the Periodic Surveillance and Preventive Maintenance Program such that SSCs within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.16 **Reactor Coolant System Alloy 600 Inspection Program**

Program Description

The Reactor Coolant System Alloy 600 Inspection Program manages crack initiation and growth due to primary water stress corrosion cracking (PWSCC) of RCS pressure boundary nickel-based alloy components (e.g., Alloy 600/690 reactor vessel/head penetration nozzles, Inconel 82/182, 82/152, and 52/152 weld joints). The program includes (a) PWSCC susceptibility assessment using industry models to identify susceptible components, (b) monitoring and control of reactor coolant chemistry to mitigate PWSCC, (c) inservice inspections (ISI) of reactor vessel/head penetrations and RCS pressure boundary welds in accordance with ASME Section XI, Subsection IWB, Table IWB 2500-1, and (d) augmented inspections or preemptive repair/replacement of susceptible components or welds.

The Reactor Coolant System Alloy 600 Inspection Program consists of several preexisting activities and several new activities. The program includes:

- Identification of components within the program scope (new).
- Routine inspections (preexisting).
- Primary Chemistry Control (preexisting).
- Assessment of component or weld susceptibility to PWSCC (preexisting for vessel head penetrations (VHP), new for other components).
- Safety evaluations for components that are at high risk of PWSCC (preexisting for VHP, new for other components).
- Determination of corrective actions for components judged to have a high probability of PWSCC (new). Corrective actions will be chosen from among the following options:
  - Augmented inspection,
  - Preemptive repair/replacement, and/or
  - Mitigation.

NUREG-1801 Consistency

The Reactor Coolant System Alloy 600 Inspection Program is a new program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M11, “Nickel-Alloy Nozzles and Penetrations” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Detection of Aging Effects
- Monitoring and Trending
- Operating Experience

Enhancements

Enhancements to the Reactor Coolant System Alloy 600 Inspection Program include: incorporation of acceptance criteria for RPV head visual inspections, development of new implementing documents to meet the commitments made in response to NRC Bulletin 2002-02, NRC Bulletin 2003-02 and the requirements of NRC Order EA-03-009, and the performance of susceptibility assessments and development of corrective action plans and /or inspections for nickel-based components and welds not addressed under the evaluations performed for reactor vessel head penetrations. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below

Enhancements are scheduled for completion consistent with the commitments made in the response to NRC Bulletin 2002-02, NRC Bulletin 2003-02 and the requirements of NRC Order EA-03-009, or prior to the period of extended operation, as applicable.

Aging Management Program Elements

The key elements, which are used in the Reactor Coolant System Alloy 600 Inspection Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M11, “Nickel-Alloy Nozzles and Penetrations,” is also provided below.

Scope of Program

The Reactor Coolant System Alloy 600 Inspection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Class 1 Piping/Components	Reactor Vessel

Nickel-based alloy components and welds, that are part of the Reactor Coolant System (RCS) pressure boundary are within the scope of the Reactor Coolant System Alloy 600 Inspection Program.   These components include the CRDM adapter tubes, reactor vessel bottom head instrumentation penetrations and associated Inconel attachment welds to the reactor vessel closure head or bottom head, Inconel 82/182 butt welds of the Alloy 600 CRDM adapter tube and bottom mounted instrumentation nozzles to stainless steel safe ends, PBNP-2 steam generator vent nozzles and the associated Inconel 152 welds, and the PBNP-2 Inconel 82/152 steam generator primary nozzle-to-safe end welds.

This program credits the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program for the performance of required inservice inspections in accordance with ASME Section XI, Subsection IWB. This program also credits the Water Chemistry Control Program for monitoring and control of reactor coolant water chemistry to mitigate PWSCC.

The susceptibility of nickel-based alloy components and welds will be evaluated under the Reactor Coolant System Alloy 600 Inspection Program. Currently only the VHP and BMI nozzles have been identified as warranting augmented inspections. The susceptibility assessment performed in response to GL 97-01 has been replaced by a simplified time-temperature model. For reactor VHPs, the simplified time-temperature model described in “PWR Materials Reliability Program Response to NRC Bulletin 2001-01” (MRP-48) and NRC Order EA-03-009, was used to assess PWSCC susceptibility. For components not addressed as part of the reactor VHP, the program requires PBNP to use the most up-to-date industry models available for PWSCC susceptibility determinations.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The PBNP program meets the intent of the NUREG-1801 program through the use of a susceptibility model to determine inspection timing, but the model differs from the one described in the NUREG-1801 program. The NRC Order specifies a methodology to assess VHP susceptibility different than the model used in the GL 97-01 response, which is referred to in NUREG-1801. The NUREG-1801 program does recognize that the program and industry models may need to change as industry operating experience is accumulated. The NUREG-1801 program also references the 1995 Edition through 1996 addenda of ASME Section XI, Subsection IWB for the inservice inspections of the VHP. PBNP currently uses the 1998 Edition through 2000 addenda as discussed in the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. IWB

Examination Categories B-P and B-O apply to the VHP. The later code edition/addenda encompasses the requirements of the earlier code for these two examination categories.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

This program credits the Water Chemistry Control Program for monitoring and control of reactor coolant water chemistry to mitigate PWSCC.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The Reactor Coolant System Alloy 600 Inspection Program incorporates routine inspections performed under the ISI program and augmented inspections capable of detecting and sizing non-throughwall cracks if warranted by individual component susceptibility. For VHP, augmented visual inspections for leakage and volumetric and/or surface exams are performed in accordance with regulatory requirements and commitments.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

Susceptibility assessments of the VHPs will be based on the methodology prescribed by NRC Order EA-03-009 rather than the model referenced in the GL 97-01 response. Inspections will consist of augmented visual inspections capable of detecting very small amounts of leakage.

The Reactor Coolant System Alloy 600 Inspection Program does not evaluate the need to install a leakage detection system. NRC GL 97-01 referenced a previous safety evaluation, which recommended enhanced leakage detection by either visual examination of the reactor vessel head (RVH) or installation of an on-line leakage detection system installed in the RVH area. Therefore, the “leakage detection system” referred to in the NUREG-1801 program and attributed to NRC GL 97-01 is satisfied by the visual inspections since they will be capable of detecting very small amounts of leakage.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The PBNP program meets the intent of the NUREG-1801 program through the use of a susceptibility model prescribed by NRC Order EA-03-009 to determine inspection timing, which differs from the one described in the NUREG-1801 program.

Enhancements to this program include the development of new implementing documents to meet the commitments made in response to NRC Bulletin 2002-02, NRC Bulletin 2003-02 and the requirements of NRC Order EA-03-009, and the performance of susceptibility assessments and development of corrective action plans and/or inspections for nickel-based components and welds not addressed under the evaluations performed for reactor vessel head penetrations.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

Periodic reactor pressure vessel (RPV) head inspections are performed as required to meet commitments made in response to NRC Bulletin 2002-02 and the requirements of NRC Order EA-03-009. Periodic inspection of the lower RPV dome will be conducted as described in PBNP's response to NRC Bulletin 2003-02. Inspections of other components are based on the results of the susceptibility assessment and corrective action plan.

This program credits the Water Chemistry Control Program for monitoring and control of reactor coolant water chemistry to mitigate PWSCC.

This element is includes exceptions to the corresponding NUREG-1801 aging management program element. The NUREG-1801 program refers to an integrated inspection program based on NRC GL 97-01. The PBNP program for RPV head and lower dome penetrations complies with regulatory requirements developed since the issuance of GL 97-01 to address more recent industry operating experience.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Acceptance Criteria

Indications detected will be evaluated in accordance with ASME Section XI requirements. Additionally, if non-throughwall cracks are detected by a volumetric inspection, the evaluation of the component's acceptability for continued service will consider the most current crack growth rate information. Any evidence of leakage noted during the RPV head or lower dome visual inspections is considered a recordable indication requiring further evaluation.

Enhancements to plant procedures will result in the creation of acceptance criteria for RPV head visual inspections.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Reactor Coolant System Alloy 600 Inspection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

Extensive industry operating experience has been reviewed in developing the Reactor Coolant System Alloy 600 Inspection Program. The review of industry operating experience revealed numerous occurrences of cracks and leaks of Alloy 600 nozzles and penetrations with partial penetration welds. Most of the cracks of Alloy 600 penetrations caused by PWSCC have initiated on the inner diameter of the penetration near the elevation of the J-groove weld and have been short and axially oriented. Recently, a few PWRs have experienced circumferential cracking, outer diameter initiated cracking, and cracking initiating in the J-groove weld, in CRDM penetrations. A PWR has experienced a throughwall PWSCC crack in an Inconel 82/182 piping butt weld, one PWR has experienced severe degradation of the RPV head due to boric acid corrosion resulting from a VHP leak and another PWR has detected axial cracking in reactor vessel BMI penetrations.

A review of plant-specific operating experience was also performed. A Condition Report was initiated to address the potential for a Loss of Coolant Accident (LOCA) created by the generic industry issue of PWSCC of reactor vessel head penetrations. A Justification for Continued Operation was developed as a result. Corrective actions included revision of existing guidance documents to provide more direction for responding to increasing RCS leakage, inspection of the PBNP-1 and PBNP-2 reactor vessel heads for gross leakage indications, and a review of the Westinghouse safety evaluation of PWSCC of reactor vessel head penetrations. The condition report was closed out on October 7, 1993.

An additional action taken in response to the generic industry issue of reactor vessel head penetration PWSCC was a volumetric examination of the PBNP-1 RVH penetrations, conducted in 1994. The examination revealed no indications. PBNP has committed to performing effective visual examinations of the reactor pressure vessel head and nozzles of PBNP-1 and PBNP-2 in response to NRC Bulletin 2001-01 and NRC Bulletin 2002-02. The base metal RPV head inspection performed on PBNP-1 and -2 in 2002 revealed no evidence of boric acid deposition or wastage of the RPV head on either unit. The volumetric and surface examinations of the PBNP-2 VHP in September of 2002, noted one VHP nozzle with a recordable fabrication indication in the nozzle wall approximately ¼” below the weld toe. The remaining 48 VHP nozzles and vent line did not contain any recordable indications.

In addition, PBNP personnel will continue to follow industry developments related to PWSCC of Alloy 600 through participation in the EPRI MRP Alloy 600 ITG, WOG, and other industry groups as applicable. PBNP will continue to participate in industry integrated susceptibility assessment and inspection programs that may differ in the details, but will be consistent with the intent of the guidelines of NRC GL 97-01, “Degradation of CRDM/CEDM Nozzle and Other Vessel Closure Head Penetrations,” and the previously discussed NRC Bulletins and Order.

The visual examinations for system leakage performed under the ISI program have not found any evidence of leakage from Alloy 600 VHP or other components. PBNP has also not experienced significant resin intrusions that would lead to contamination of the RCS by sulfates. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. The NUREG-1801 program refers to an integrated inspection program based on NRC GL 97-01. The PBNP program for RPV head penetrations complies with regulatory requirements developed since the issuance of GL 97-01 to address more recent operating industry experience.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Conclusion

The Reactor Coolant System Alloy 600 Inspection Program provides reasonable assurance that the effects of aging will be managed such that systems and components within the scope of the program will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation.

B2.1.17 Reactor Vessel Internals Program

Program Description

The Reactor Vessel Internals Program manages the aging effects for reactor vessel internals (RVI). The program provides for (a) Inservice Inspection (ISI) in accordance with ASME Section XI requirements, including examinations performed during the 10-year ISI examination; (b) An evaluation that will identify leading locations with respect to irradiation assisted stress corrosion cracking (IASCC) and irradiation embrittlement, appropriate non-destructive examination techniques, and an examination schedule for these locations; (c) Baffle-former/barrel-former bolt evaluation that will determine the acceptability of the current arrangement or if ultrasonic examination and/or replacement of these bolts is necessary; (d) For cast austenitic stainless steel components subject to neutron fluence in excess of 10^{17} n/cm^2 or determined to be susceptible to thermal embrittlement, an augmented inspection of components experiencing significant tensile stress (>5 ksi); (e) Evaluation of the significance of void swelling; (f) monitoring and control of reactor coolant water chemistry in accordance with the Water Chemistry Control Program to mitigate SCC or IASCC; (g) Participation in industry initiatives that will generate additional data on aging mechanisms relevant to RVI and develop appropriate inspection techniques to permit detection and characterization of features of interest; and (h) One-time inspection of the internals hold-down spring for evidence of stress relaxation.

This program is credited by the Bolting Integrity Program for the inspection of bolting internal to the reactor vessel. In addition to the requirements of ASME Section XI, Subsection IWB, this program monitors for loss of preload caused by stress relaxation of bolted joints and specifically addresses cracking in baffle/barrel former bolts.

NUREG-1801 Consistency

The Reactor Vessel Internals Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.M16, “PWR Vessel Internals,” and XI.M13, “Thermal Aging Embrittlement and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Detection of Aging Effects
- Monitoring and Trending
- Acceptance Criteria

Enhancements

Enhancements to the Reactor Vessel Internals Program include determination and implementation of augmented inspection requirements necessary to ensure that the RVI components will maintain the capability to perform their intended functions during the period of extended operation. The augmented examination requirements apply to components which have not been determined to have less than 5 ksi maximum tensile stress during ASME Code Level A, B, C, or D conditions. The augmented examinations will focus on the leading locations of non CASS components with respect to IASCC and irradiation embrittlement and the leading locations of CASS components with respect to fluence and thermal aging embrittlement screening criteria. Augmented examinations for void swelling will be performed, as necessary, based on the results of industry research and operating experience. A determination will be made as to the need for further examinations and/or replacement of the baffle bolts and split pins in PBNP 1 and 2. Point Beach will actively participate in industry groups studying RVI materials degradation issues and implement NRC approved industry activities resulting from the EPRI MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort. These enhancements are required to satisfy these NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Reactor Vessel Internals Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.M.16, “PWR Vessel Internals,” and XI.M.13, “Thermal Aging Embrittlement and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS),” is also provided below.

Scope of Program

The Reactor Vessel Internals Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Reactor Vessel Internals

RVI components are within the scope of the Reactor Vessel Internals Program. The major components of the RVI can be categorized as belonging to the upper or lower internals. The major components of the lower internals are the thermal shield, upper and lower core barrel, core barrel flange, core barrel outlet nozzles, baffle and former plates, lower core plate, lower support forging, secondary core support, bottom mounted instrumentation columns, lower support plate columns, and diffuser plate. Baffle-former bolts and barrel-former bolts are included in the lower internals. Radial support keys attached to the lower internals engage the clevis inserts, which are attached to the reactor vessel. The upper internals major components are the upper support columns, control rod guide tubes, upper core plate, upper support plate, and upper instrumentation columns and supports. Components that form the interface between core supports and internals or core supports and vessel are within the scope of the program. These include the upper core plate alignment pins, fuel alignment pins, internals hold-down spring, head/vessel alignment pins, and clevis inserts.

Virtually all these components are fabricated from various types of wrought austenitic stainless steel; however, a few components are fabricated from cast austenitic stainless steel (CASS). Guide tube split pins are fabricated from nickel-based alloy X-750.

The program relies on the ASME Section XI examinations of the RVI to detect the applicable aging effects. This program credits the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program for the code required ISI examinations of the RVI. For some components, the VT-3 examination required by ASME Section XI may not be adequate to detect the effects before the component intended function is compromised. The need for augmented examinations will be determined by evaluations of the susceptibility to the applicable aging effects for each RVI component that requires aging management. The examination method and sensitivity are determined based on the size of the smallest crack, or extent of other degradation that must be detected to ensure the intended function of the RVI component is not compromised. Fluence, temperature, and stress analyses may be used as inputs to the susceptibility evaluations, in addition to industry and plant-specific operating experience.

For CASS components that are part of the RVI, PBNP will determine the EOEL fluence. If the fluence will not exceed 10^{17} n/cm^2, the significance of thermal aging will be determined by comparison with the screening criteria, based on delta ferrite content, molybdenum content, and casting method, as described in NUREG-1801, Section XI.M13.

This program also credits the One-Time Inspection Program for the management of stress relaxation of the lower internals hold-down spring.

This element includes exceptions to the corresponding NUREG-1801 aging management program elements. NUREG-1801 references the 1995 Edition through 1996 addenda of ASME Section XI, Subsection IWB for the inservice inspections of RVI. PBNP currently uses the 1998 Edition through 2000 addenda as discussed in the ASME Section XI, Subsections IWB, IWC, and

IWD Inservice Inspection Program. ASME Section XI, IWB-2500, Examination Category B-N-3 applies to the RVI. The later code edition/addenda encompasses the requirements of the earlier code for this examination category.

Enhancements to the Reactor Vessel Internals Program will result in the following:

1. For non-CASS RVI components other than baffle-former or barrel-former bolts:
   - Determine leading locations in the RVI with respect to IASCC and irradiation embrittlement. The determination of leading locations may include a mechanical loading assessment of the component.
   - For leading components/locations with respect to IASCC and irradiation embrittlement:
     a. If the mechanical loading assessment described above indicated the maximum tensile stress during ASME Code Level A, B, C, or D conditions is < 5 ksi, no augmented examination is necessary.
     b. If augmented examination is necessary, determine the size of crack that must be detected in order to ensure that the components will maintain the capability to perform their intended functions. Determine appropriate examination technique, accordingly. Determine reexamination interval, if necessary, based on anticipated crack growth rates.
2. For CASS RVI components:
   - Perform a fluence analysis to determine if the fluence will exceed 10^{17} n/cm^2 by the end of extended life.
   - For components in which the fluence will not exceed 10^{17} n/cm^2 by the end of extended life, determine the significance of thermal aging embrittlement by comparison to the screening criteria described in NUREG-1801, Section XI.M13, “Thermal Aging Embrittlement and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel.”
   - The following options exist for components that exceed 10^{17} n/cm^2 fluence, or for which thermal aging embrittlement is judged to be significant:
     a. Determine the size of crack that must be detected in order to ensure that the components will maintain the capability to perform their intended functions. Determine appropriate examination

technique, accordingly. Determine reexamination interval, if necessary, based on anticipated crack growth rates.

b. Perform a mechanical loading assessment of the component. If the maximum tensile stress during ASME Code Level A, B, C, or D conditions is < 5 ksi, no augmented examination is necessary.

c. The component may be replaced.

3. For baffle-former and barrel-former bolts:
   - Determine need for UT examination or preemptive replacement of PBNP-1 baffle-former bolts.
   - Schedule examination and/or replacement of baffle-former bolts for PBNP-1, as necessary.
   - Monitor industry operating experience with respect to cracking of Type 316 stainless steel baffle-former bolts, such as the replacement baffle bolts in the PBNP-2 internals. Plan examination or corrective action for the replacement baffle-former bolts if a need is indicated by industry operating experience.
   - Based on baffle-former bolt examination results and/or industry operating experience, determine the need for a UT examination and/or replacement of barrel-former bolts at PBNP-1 and PBNP-2.
4. For split pins:
   - Determine need to examine or preemptively replace original and “Rev B” split pins on PBNP-1 and -2.
   - Schedule examinations or replacements, as necessary.
5. Monitor industry research on the significance of void swelling to RVI intended functions. Plan augmented examinations for void swelling, as necessary, based on the results of the industry research.
6. Actively participate in industry groups studying RVI materials degradation issues, such as the EPRI MRP RI-ITG and Westinghouse Owner's Group. Implement NRC approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Preventive Actions

The Water Chemistry Control Program is credited for monitoring and control of reactor coolant water chemistry to prevent or mitigate the effects of SCC and IASCC. Additionally, the guide tube split pins in PBNP-1 have all been replaced with pins made from the same alloy with a more SCC-resistant heat treatment. In PBNP-2, the pins on two guide tubes were replaced and the remaining pins were verified to have been solution heat treated above 1800 degrees F., although it is assumed that they are still susceptible to SCC because the initial installation torque was substantially higher than that used in the replacements. A portion of the baffle former bolts in the PBNP-2 internals have been replaced with a more crack resistant material. For RVI CASS components, the program consists of evaluations and inspections. There are no preventive actions to mitigate thermal aging, neutron irradiation embrittlement or void swelling.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Parameters Monitored or Inspected

The program monitors for cracking, loss of fracture toughness, loss of bolted joint preload, wear, and change of dimensions through ASME Section XI examinations and augmented nondestructive examinations.

The program monitors the effects of loss of fracture toughness of components by identifying the CASS materials that either have a neutron fluence of greater than 10^{17} n/cm^2 or are determined to be susceptible to thermal aging embrittlement. For these components, PBNP will evaluate the need for and the characteristics of an augmented examination. As an alternative to an augmented examination, a mechanical loading assessment may be conducted.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Detection of Aging Effects

Visual examinations are used to detect cracking, loss of preload, and wear. The type of visual examination utilized will be, as a minimum, the VT-3 examination specified by ASME Section XI, Subsection IWB, Category B-N-3. Augmented examinations for cracking may consist of VT-1, enhanced VT-1 examinations (defined as a visual examination with a finer resolution than the standard VT-1 requirements in ASME Section XI), or a volumetric examination when warranted by the size and location of the crack that must be detected to preserve intended functions. For baffle-former bolts and other bolts that are largely inaccessible for visual examination, ultrasonic testing (UT) or other appropriate NDE technique will be used to detect cracking.

For components in which the fluence will exceed 10^{17} n/cm^2, or for components that will not receive 10^{17} n/cm^2 but for which thermal aging is judged to be significant based on the screening criteria, PBNP will evaluate the need for an augmented examination covering portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking. As an alternative to an augmented examination, a mechanical loading assessment may be conducted. If the maximum tensile stress during ASME Code Level A, B, C, or D conditions is < 5 ksi, no augmented examination is necessary.

Indications found during examinations will be evaluated using the criteria found in ASME Section XI, IWB-3500. Flaw tolerance evaluations will utilize the IWB-3640 procedure for submerged arc welds, with the modification that the delta ferrite content may be up to 25% rather than 20% delta ferrite as required by IWB-3641.

This element includes exceptions to the corresponding NUREG-1801 aging management programs elements. NUREG-1801 provides a specific example of an acceptable supplemental or enhanced examination as a VT-1 examination with .0005 inch resolution. This program does not specify resolution requirements for enhanced VT-1 examination, but rather requires examination methods sufficient to detect a crack of such size that crack growth during the interval until the next examination will not result in a crack of critical size or larger.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Monitoring and Trending

The VT-3 examination per ASME Section XI, Subsection IWB, Category B-N-3 is performed once per 10-year interval on each accessible part of the RVI. Augmented examinations for cracking in components susceptible to cracking or loss of fracture toughness, and ultrasonic examinations of baffle-former bolts for cracking (if required), will be scheduled as either periodic, or one-time examinations. With respect to augmented examinations of component types susceptible to IASCC and irradiation embrittlement, the highest susceptibility components, with respect to fluence, temperature and stress, will be selected for examination. If these leading components are found to be free of cracking, less susceptible components may not require examination. The scheduling of future augmented examinations will depend on the results of the initial examination.

This element includes exceptions to the corresponding NUREG-1801 aging management program elements. NUREG-1801 specifies examination schedules in accordance with IWB-2400, which requires core support structures to be inspected once during each 10-year interval. While this applies to the VT-3 examination, some augmented examinations may be performed at a different frequency or only one-time based on the susceptibility evaluations and examination results.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Acceptance Criteria

For examinations conducted in accordance with ASME Section XI, indications or relevant conditions of degradation detected will be evaluated in accordance with IWB-3100, which refers to acceptance standards contained in IWB-3400 and IWB-3500. The criteria of IWB-3500 will be used for CASS components with flaw tolerance evaluations in accordance with the IWB-3640 procedure for submerged arc welds, with the modification that the delta ferrite content may be up to 25% rather than 20% delta ferrite as required by IWB-3641. However, any of the acceptance methods of IWB-3132 may be used (volumetric or surface examination, repair/replacement, or analytical evaluation).

This element includes exceptions to the corresponding NUREG-1801 aging management program elements. NUREG-1801, Section XI.M16, “PWR Vessel Internals,” refers to the 1995 edition through 1996 addenda of ASME Section XI. The plant uses the 1998 edition through 2000 addenda. There are no appreciable differences in the applicable portions of the code editions.

Therefore, PBNP meets the intent of these NUREG-1801 aging management program elements.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Administrative Controls

The Reactor Vessel Internals Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Operating Experience

Industry operating experience has been reviewed during the development of the Reactor Vessel Internals Program. The experience reviewed includes IN 98-11, “Cracking Of Reactor Vessel Internal Baffle Former Bolts In Foreign Plants,” and IN 84-18, “Stress Corrosion Cracking in PWR Systems.” Most of the industry operating experience reviewed has involved cracking of austenitic stainless steel baffle-former bolts, or SCC of high-strength internals bolting. SCC of guide tube split pins has also been reported.

A review of plant-specific operating experience with RVI reveals that PBNP has responded to industry operating experience regarding RVI degradation. Two examples that demonstrate PBNP's response to industry operating experience with RVI are augmented examination and replacement of guide tube split pins, and augmented examination and replacement of baffle-former bolts. Guide tube split pins were replaced at PBNP-1 and PBNP-2 in response to SCC failures of these pins in other Westinghouse RVI. A more SCC-resistant heat treatment was applied to the replacement pins. An augmented examination via UT was conducted on the baffle-former bolts of PBNP-2. The UT examination identified a number of bolts with indications indicative of crack like flaws. A number of bolts sufficient to guarantee the structural margins of the baffle-former joints were replaced, including all bolts with UT indications. The replacement bolts are fabricated from a more IASCC-resistant material. PBNP will participate in the EPRI RI-ITG, which is engaged in ongoing research into aging effects of RVI, and provides guidance to utilities on corrective actions for these aging effects. PBNP also participates in Westinghouse Owner's Group activities related to RVI.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Reactor Vessel Internals Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Conclusion

The Reactor Vessel Internals Program provides reasonable assurance that the effects of aging will be managed such that the intended functions of the RVI will be maintained consistent with the current licensing basis for the period of extended operation.

B2.1.18 Reactor Vessel Surveillance Program

Program Description

The Reactor Vessel Surveillance Program manages the aging effect reduction of fracture toughness due to neutron embrittlement of the low alloy steel reactor vessels. Monitoring methods will generally be in accordance with 10 CFR 50, Appendix H, but may also include direct measurement of fracture toughness specimens to support a Master Curve Approach. This program includes (a) capsule insertion, withdrawal and materials testing/evaluation, (including upper shelf energy and RT_{NDT} determinations), (b) fluence and uncertainty calculations, (c) monitoring of Effective Full Power Years (EFPY), (d) development of pressure-temperature limitations, and (e) determination of low-temperature overpressure protection (LTOP) set points. The program ensures the reactor vessel materials (a) meet the fracture toughness requirements of 10 CFR 50, Appendix G, and (b) have adequate margins against brittle fracture caused by Pressurized Thermal Shock (PTS) in accordance with 10 CFR 50.61; or alternatively, via the Master Curve Approach, which involves the use of directly measured fracture toughness data.

The Reactor Vessel Surveillance Program consists of five major subprograms:

- Surveillance Capsule Insertion, Withdrawal, and Evaluation,
- Fluence and Uncertainty Calculations,
- Monitoring of Effective Full Power Years (EFPY),
- Development of Pressure-Temperature Limit Curves, and
- Calculation and Monitoring of Low Temperature Overpressure Protection (LTOP) Setpoints.

NUREG-1801 Consistency

The Reactor Vessel Surveillance Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M31, “Reactor Vessel Surveillance” (Reference 3). The Reactor Vessel Surveillance Program is also an existing program that consists of the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants.”

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Preventive Actions
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Monitoring and Trending
- Acceptance Criteria

Enhancements

Enhancements to the Reactor Vessel Surveillance Program include changes to the FSAR and TRM to reflect the materials and withdrawal schedule of the new surveillance capsule and revisions to plant procedures to clarify organizational responsibilities, provide allowance for the Master Curve Approach, describe the plan/schedule for removal, testing and evaluation of surveillance capsules, and to evaluate fracture toughness margin through the period of extended operation. Additionally, a revised fracture mechanics TLAA evaluation will be performed if needed to address uprated power conditions and/or operation without hafnium power suppression absorber rods installed.

These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Reactor Vessel Surveillance Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M31, “Reactor Vessel Surveillance,” is provided below. An evaluation of each key element against the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” was also conducted.

Elements of the first three listed subprograms (i.e., Surveillance Capsule Insertion, Withdrawal and Evaluation, Fluence and Uncertainty Calculations, and Monitoring of Effective Full Power Years), are addressed by the NUREG-1801 program. The subprograms for the Calculation and Monitoring of LTOP Setpoints and Development of Pressure-Temperature Limit Curves are not addressed by the NUREG-1801 program.

Scope of Program

The Reactor Vessel Surveillance Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Reactor Vessel

The Reactor Vessel Surveillance Program only applies to the PBNP-1 and PBNP-2 reactor pressure vessels.

<u>Surveillance Capsule Insertion, Withdrawal, and Evaluation</u>

The program controls the development of surveillance capsule insertion and withdrawal schedules and capsule materials testing. Although the original surveillance capsules did not contain the most limiting material with respect to embrittlement, an additional surveillance capsule was installed in 2002 that contains the most limiting material. The surveillance program therefore meets the requirements of ASTM E 185-82.

The capsule installed in 2002 will be withdrawn during an outage at which it has accumulated a fluence equivalent to the 60-calendar year vessel fluence. Data from an integrated surveillance program that includes all PWRs with reactor vessels fabricated by B&W will also be used to predict embrittlement. Spare capsules remaining in both the PBNP-1 and PBNP-2 reactor vessels do not contain the most limiting materials and there are no current plans to withdraw these capsules.

The results of capsule materials testing, fluence analysis, and EFPY monitoring are used to predict the effects of neutron embrittlement through the end of extended life (EOEL). Prediction of the effects of radiation on reactor vessel beltline materials is in accordance with RG 1.99, Revision 2. Both the chemistry tables (RG 1.99, Revision 2, Position 1) and surveillance data (RG 1.99, Revision 2, Position 2) are used to project embrittlement. The limitations of RG 1.99, Revision 2, Position 1.3 are observed for material properties, temperature, material chemistry, and fluence.

The results of capsule tests, fluence analysis, and EFPY monitoring are also used to determine compliance with the PTS screening criteria of 10 CFR 50.61. If projections indicate that RT_{NDT} would exceed the PTS screening criteria prior to the amount of EFPY projected for the EOEL, PBNP will employ alternative means of demonstrating that the reactor vessel has adequate resistance to brittle fracture during a PTS event, such as application of the Master Curve Approach. In a case where the Master Curve Approach was necessary to meet the intent of 10 CFR 50.61, it would also be desirable to apply the Master Curve Approach to the development of P-T curves, which is subject to the requirements of 10 CFR 50, Appendix G. This would allow the use of less restrictive pressure-temperature limit curves. Fracture toughness specimens included in the replacement surveillance capsule installed in the PBNP-2 reactor vessel in 2002, will support future Master Curve Analyses.

Fluence and Uncertainty Calculations

Calculations are performed for the PBNP-1 and PBNP-2 reactor vessels in accordance with RG 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” The results are used as an input to embrittlement predictions.

Monitoring of Effective Full Power Years (EFPY)

EFPY monitoring is accomplished using operations data for the PBNP-1 and PBNP-2 reactors. The results are used to project the fluence corresponding to specific values of EFPY.

Development of Pressure-Temperature Limit Curves

The Reactor Vessel Surveillance Program controls the development of pressure and temperature limit curves in accordance with 10 CFR 50, Appendix G requirements. The methods of ASME Section XI, Appendix G are used to determine pressure and temperature limits. The fracture toughness used in calculating P-T limits is determined as a function of the difference in temperature from RT_{NDT}, unless the Master Curve Approach is used. RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials” is used to determine RT_{NDT}. ASME Code Case N-641 allows the use of the K_{IC} curve, an alternate fracture toughness curve to the K_{IR} curve, which is a modification to the acceptance criteria of ASME Section XI, Appendix G.

As an alternative to the use of the K_{IR} curve indexed by RT_{NDT} specified in ASME Section XI, Appendix G, the provisions of ASME Code Case N-629 allowing the use of directly measured fracture toughness data (the Master Curve Approach), may be used in the Appendix G analysis, if required to meet flaw stability requirements.

Calculation and Monitoring Of Low Temperature Overpressure Protection (LTOP) Setpoints

The Reactor Vessel Surveillance Program requires the calculation of LTOP set points for the PBNP-1 and PBNP-2 reactor coolant systems. These set points ensure that an LTOP event will not increase the probability of brittle fracture of the reactor vessels. LTOP set points include the maximum pressure allowed before the LTOP system actuates to relieve the pressure, and the temperature below which the LTOP system must be effective. These pressures and temperatures are determined using the method of ASME Section XI, Appendix G or using an alternative method provided by ASME Code Case N-641.

This element includes exceptions to the NUREG-1801 aging management program. NUREG-1801 specifies a surveillance program based on ASTM E 185, which requires the surveillance specimens to consist of C_V specimens. NUREG-1801 does not provide the option of including fracture toughness specimens in the surveillance program. NUREG-1801 also specifies the use of RG 1.99, Revision 2 to project embrittlement, which specifies the use of surveillance data from a surveillance program meeting ASTM E 185. Therefore, the use of directly measured fracture toughness data (the Master Curve Approach) to project embrittlement constitutes an exception to the NUREG-1801 program. Determination of LTOP set points is an addition to the scope of NUREG-1801, Section XI.M.31, “Reactor Vessel Surveillance.” The fluence calculation and EFPY monitoring subprograms, while not specifically discussed in NUREG-1801 provide necessary inputs to performing the evaluations required by NUREG-1801; therefore, are implicitly included within the scope of the NUREG-1801 program.

PBNP meets the intent of this NUREG-1801 aging management program.

Preventive Actions

This surveillance program determines neutron embrittlement for upper-shelf energy and pressure-temperature limits for 60 years in accordance with the RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials.”

<u>Surveillance Capsule Insertion, Withdrawal, and Evaluation</u>

Calculations demonstrating that the PBNP-1 and PBNP-2 reactor vessels meet the PTS screening criteria of 10 CFR 50.61 ensure the probability of brittle fracture of the reactor vessels during a PTS event is acceptably low. If the PTS screening criteria cannot be met, the Master Curve Approach may be used to determine an equivalent low probability of brittle fracture for the reactor vessel as that represented by the PTS screening criteria of 10 CFR 50.61.

<u>Fluence and Uncertainty Calculations</u>

Fluence and uncertainty calculations do not constitute preventive actions.

<u>Monitoring of Effective Full Power Years (EFPY)</u>

EFPY monitoring is a monitoring activity, not a preventive action.

<u>Development of Pressure-Temperature Limit Curves</u>

The development of, and operation within, P-T limit curves minimizes the probability of brittle fracture of the reactor vessel during normal operation.

<u>Calculation and Monitoring of Low Temperature Overpressure Protection (LTOP) Setpoints</u>

The LTOP system with the actuation setpoints and operational restrictions established by the LTOP analysis, minimizes the probability of an LTOP event, and therefore, helps to minimize the probability of reactor vessel brittle fracture.

This element includes exceptions to the NUREG-1801 aging management program. NUREG-1801 does not provide for use of the Master Curve Approach to demonstrate that reactor vessels possess adequate resistance to brittle fracture.

PBNP meets the intent of this NUREG-1801 aging management program.

Parameters Monitored or Inspected

Surveillance Capsule Insertion, Withdrawal, and Evaluation

The program monitors the effects of neutron irradiation on the PBNP-1 and PBNP-2 reactor vessel beltline materials. Fracture toughness of beltline materials is indirectly monitored through measurement of the impact energy of Charpy V-Notch (C_V) specimens, made from representative materials from the PBNP reactor vessels beltline regions. C_V test results from capsules irradiated in other PWRs participating in an integrated surveillance program are also used to aid in trending the change in material properties of the PBNP reactor vessels. Fracture toughness specimens to be irradiated in the PBNP-2 vessel and in the Master Integrated Reactor Vessel Surveillance Program (MIRVSP) will be withdrawn and tested. The fracture toughness results may be used to support a Master Curve Analysis for PBNP-2. The surveillance capsules also contain neutron dosimetry that monitors the amount of neutron fluence received by the test specimens. The vessel fluence is then used to calculate RT_{NDT} using the method of RG 1.99, Revision 2.

Fluence and Uncertainty Calculations

This subprogram does not monitor, inspect, or test any parameters. Neutron fluence measurements acquired under the surveillance capsule insertion, withdrawal and testing subprogram are used to validate analytical models that determine the fluence received by the reactor vessel.

Monitoring of Effective Full Power Years (EFPY)

Effective Full Power Years (EFPY) are monitored and used to predict the fluence that the vessel will accumulate at some future time, which is then used to predict change in RT_{NDT} and upper shelf energy (USE).

Development of Pressure-Temperature Limit Curves

No parameters are monitored or inspected under this subprogram.

Calculation and Monitoring of Low Temperature Overpressure Protection (LTOP) Setpoints

LTOP system relief valve operation is monitored to determine whether an LTOP event could have occurred had the LTOP system been inoperable. Operation within the P-T limits is also monitored.

This element includes exceptions to the NUREG-1801 aging management program. NUREG-1801 does not provide for directly monitoring fracture toughness.

PBNP meets the intent of this NUREG-1801 aging management program.

Detection of Aging Effects

Surveillance Capsule Insertion, Withdrawal, and Evaluation

Aging effects are detected through testing of surveillance materials. C_V tests are performed to determine the decrease in USE and increase in transition temperature RT_{NDT}, for materials that closely match reactor vessel beltline materials. If the Master Curve Approach is required, aging effects may also be detected through direct measurement of fracture toughness of materials that closely match PBNP reactor vessel beltline materials.

Fluence and Uncertainty Calculations

This subprogram does not detect aging effects.

Monitoring of Effective Full Power Years (EFPY

This subprogram does not detect aging effects.

Development of Pressure-Temperature Limit Curves

This subprogram does not detect aging effects.

Calculation and Monitoring of Low Temperature Overpressure Protection (LTOP) Setpoints

This subprogram does not detect aging effects.

Enhancements will be made to revise the surveillance capsule withdrawal schedule contained in the PBNP FSAR and TRM, as necessary, to reflect the planned withdrawal of the replacement capsule that was installed in PBNP-2 during the 2002 refueling outage. A description of the materials to be included in this capsule, including fracture toughness specimens, must also be added to the PBNP FSAR. A revised fracture mechanics TLAA evaluation will be performed if needed to address uprated power conditions and/or operation without hafnium power suppression absorber rods installed. In addition, plant procedures will be modified as follows:

- Add a requirement that the reactor vessel engineer shall ensure that all withdrawn surveillance capsules not discarded as of August 31, 2000, are placed in storage, for the purposes of future reconstitution and use, if necessary.
- Add a requirement that the reactor vessel engineer shall ensure that the number of EFPY accrued by PBNP-1 and PBNP-2 is updated by January 1 of each year."
- Add a requirement that the reactor vessel engineer shall ensure that the fluence and uncertainty calculations for PBNP-1 and PBNP-2 are updated periodically. The reactor vessel engineer should trend the rate of fluence accumulation versus EFPY. Based on the updated projection of fluence versus EFPY, the reactor vessel engineer shall review the number of EFPY associated with the expiration of the current P-T limits to determine if this projected amount of EFPY remains valid."
- Add a requirement that a determination of the number of EFPY accumulated by January 1 of the current year shall be performed and documented annually.
- Allow either the use of the methods of RG 1.99, Revision 2 to determine the irradiated material properties used in developing P-T curves, or use of direct fracture toughness measurements (i.e., Master Curve Approach) if the requirements of 10 CFR 50, Appendix G, cannot be met using properties determined by the former method.
- Add a requirement that existing equivalent margins analyses for low USE be evaluated to determine whether they will continue to be valid until the end of license extension. If the analyses will not remain valid until the end of the extended license, revise the analyses as necessary to extend their applicability until the end of license extension or take other actions to ensure USE remains adequate.
- Specify that the methods of RG 1.99, Revision 2, are used to demonstrate compliance with the fracture toughness requirements of 10 CFR 50, Appendix G.
- Allow the use of alternative methods for demonstrating that the intent of 10 CFR 50.61 is met, other than comparison of RT_{NDT} to the PTS screening criteria. Such alternate methods could include a Master Curve Analysis.
- Add a description of the methodology of fluence and uncertainty calculations.

- Add a requirement to install neutron dosimetry if the last surveillance capsule in PBNP -2 is withdrawn prior to the 55th year of operation.
- Add a description of the plan/schedule for removal, testing and evaluation of surveillance capsules.

This element includes exceptions to the corresponding NUREG-1801 aging management program. NUREG-1801 does not provide the option to detect reduction of fracture toughness via specimens other than C_V specimens (e.g., Master Curve Approach).

PBNP meets the intent of this NUREG-1801 aging management program.

Monitoring and Trending

Surveillance Capsule Insertion, Withdrawal, and Evaluation

Monitoring of reactor vessel beltline fracture toughness is accomplished through testing of surveillance specimens from surveillance capsules that are periodically withdrawn from the vessels. Trending is accomplished through the RG 1.99, Revision 2 methods for projection of RT_{NDT} and USE. Projection of the increase in RT_{NDT} and the decrease in USE provides early indication if the fracture toughness properties of the PBNP reactor vessel beltline materials will fail to meet regulatory requirements. The RT_{NDT} projection is compared to the PTS screening criteria of 270 degrees F for plates, forgings, and axial welds, and 300 degrees F for circumferential welds specified in 10 CFR 50.61. USE projections are compared against the requirement to maintain 50 ft-lbs or greater given by 10 CFR 50, Appendix G.

When the Master Curve Approach is used, the aging effect of reduction in fracture toughness will be monitored through direct measurements of fracture toughness from materials representative of PBNP beltline materials, and trended by the projected increase in the reference temperature RT_{T0}.

Fluence and Uncertainty Calculations

Fluence measurements from capsules are trended to verify that actual fluence is adequately represented by fluence models, and to project fluence for future dates. A surveillance capsule containing neutron dosimetry, or some form of neutron dosimetry, will remain installed in the reactor vessels until at least the 55th year of operation.

Monitoring of Effective Full Power Years (EFPY)

EFPY are monitored and trended to allow the EFPY for particular calendar dates, such as the end of the current and extended license periods, to be projected, and to establish deadlines for revising P-T curves that are valid only to a particular number of EFPY. These projections will be extended to a number of EFPY corresponding to the end-of-extended-life (EOEL).

Development of Pressure-Temperature Limit Curves

This subprogram does not perform trending, but relies on the trending of changes in material properties, fluence, and EFPY to set limits on P-T curve validity.

Calculation and Monitoring of Low Temperature Overpressure Protection (LTOP) Setpoints

PBNP monitors and trends actuation of relief valves relied on for LTOP protection, to determine if the actuation is a reportable event. This subprogram relies on the trending of changes in material properties, fluence, and EFPY, to determine the inputs to calculations of LTOP set points.

This element includes exceptions to the NUREG-1801 aging management program. NUREG-1801 does not provide for trending the increase in directly measured fracture toughness (i.e., Master Curve Approach).

PBNP meets the intent of this NUREG-1801 aging management program.

Acceptance Criteria

Surveillance Capsule Insertion, Withdrawal, and Evaluation

The upper shelf energy of the most limiting material in the reactor vessel beltline must remain above 50 ft-lbs until the end-of-extended-life, using the methods of RG 1.99, Revision 2 with the PBNP specific and integrated surveillance program data as inputs or equivalent margin demonstrated. The RT_{NDT} of the most limiting material in the reactor vessel beltline must not exceed the PTS screening criteria specified by 10 CFR 50.61 (270 degrees F for plates, forgings, and axial welds, and 300 degrees F for circumferential welds), unless it can be demonstrated by alternate means (such as the Master Curve Approach) that the probability of brittle fracture of the reactor vessel is acceptably low in a PTS event (i.e., the intent of 10 CFR 50.61 is met).

Fluence and Uncertainty Calculations

These calculations do not have specific acceptance criteria.

Monitoring of Effective Full Power Years (EFPY)

This activity does not have specific acceptance criteria. EFPY monitoring does affect the validity of the pressure-temperature limit curves, which are linked to a specific range of EFPY.

Development of Pressure-Temperature Limit Curves

The acceptance criteria for P-T curves is that the flaw stability criteria of ASME Section XI, Appendix G, are met for all normal operating conditions as required by 10 CFR 50, Appendix G. The acceptance criteria of Appendix G may be modified through application of ASME Code Case N-641, which allows the use of the K_{IC} curve, an alternate fracture toughness curve to the K_{IR} curve. Another alternative to the use of the K_{IR} curve indexed by RT_{NDT} specified in ASME Section XI, Appendix G is use of the provisions of ASME Code Case N-629, which allows the use of directly measured fracture toughness data (i.e., Master Curve Approach) in the Appendix G analysis. Pressure-temperature curves are acceptable only through a specific value of EFPY that is based on a fluence projection for that number of EFPY.

Calculation and Monitoring of Low Temperature Overpressure Protection (LTOP) Setpoints

LTOP set points are acceptable only through a specific value of EFPY that is based on a fluence projection for that number of EFPY.

This element includes exceptions to the NUREG-1801 aging management program. NUREG-1801 does not provide for use of the Master Curve Approach, or for use of ASME Code Case N-641 fracture toughness curves when calculating P-T limit curves.

PBNP meets the intent of this NUREG-1801 aging management program.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the NUREG-1801 aging management program.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the NUREG-1801 aging management program.

Administrative Controls

The Reactor Vessel Surveillance Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the NUREG-1801 aging management program.

Operating Experience

PBNP-1 and PBNP-2 have generally operated successfully within their licensed P-T limits. The current P-T curves for PBNP-1 and PBNP-2 are valid until 34.0 EFPY. New PT curves are developed and issued, as required. An event involving the actuation of the LTOP system relief valves at PBNP-1 occurred on October 23, 1997. The event was evaluated and the conclusion was that an over pressurization event would have occurred if the LTOP system had been inoperable. A report to the NRC was therefore required. However, the LTOP system functioned correctly, preventing the over pressurization. The calculation also took no credit for manual operator action that may have prevented the over pressurization.

PBNP-1 will continue to meet the requirements of 10 CFR 50, Appendix G and 10 CFR 50.61 through the end of extended life. RT_{PTS} for the limiting material in the PBNP-2 vessel is predicted to exceed the PTS screening criteria prior to the end of license extension. The program will be modified to take advantage of the Master Curve Approach for use of directly measured fracture toughness data. Use of the Master Curve Approach will be necessary to show that the PBNP-2 reactor vessel will have adequate resistance to brittle fracture during a PTS event.

The program has been modified to incorporate data from the B&W integrated surveillance program. A replacement surveillance capsule containing materials closely matching the limiting materials for both PBNP-1 and PBNP-2 has been installed in the PBNP-2 reactor vessel during the 2002 refueling outage. The selection of materials for this capsule reflects the evolution in the understanding of the variables that control embrittlement of reactor pressure vessel steels, which resulted in a reassessment of the identity of the limiting materials in the PBNP-1 and PBNP-2 vessels.

Industry operating experience related to the Reactor Vessel Surveillance Program includes GL 92-01, Revision 1, “Reactor Vessel Structural Integrity,” and Supplement 1 to GL 92-01, Revision 1, “Reactor Vessel Structural Integrity.” PBNP's response to these documents has been incorporated into the Reactor Vessel Surveillance Program.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Reactor Vessel Surveillance Program. The Second Quarter 2000 Engineering Audit assessed the reactor vessel integrity program, as controlled by plant procedures. The audit examined several activities including a calculation of the date at which the neutron fluence would exceed the limits of the current P-T curves, the progress of a submittal to the NRC of revised P-T curves, and a calculation of the LTOP applicability date. These activities were found to have been completed satisfactorily. The auditors found that corrective actions related to previous Condition Reports had been completed, and there were no new Condition Reports. The auditors therefore judged the program to be effective. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the NUREG-1801 aging management program.

Conclusion

The Reactor Vessel Surveillance Program provides reasonable assurance that the aging effects will be managed consistent with the current licensing basis for the period of extended operation. The Reactor Vessel Surveillance Program complies with the requirements of 10 CFR 50.60, 10 CFR 50.61, and 10 CFR 50, Appendices G and H. The combination of the PBNP original surveillance program and the B&W Integrated Surveillance Program has been used to demonstrate that the reference temperature for the PBNP-1 reactor vessel limiting beltline materials will not exceed the PTS screening criteria of 10 CFR 50.61 prior to the end-of-extended life. Because the PBNP-2 reactor vessel limiting beltline material reference temperature is predicted to exceed the PTS screening criteria prior to the end of license extension, an alternative means of demonstrating compliance with the intent of 10 CFR 50.61 will be required. The alternative will consist of using directly measured fracture toughness data to show that the probability of brittle fracture of the vessel is acceptably low during a PTS event and normal operation (i.e., Master Curve Approach).

The upper shelf energy (USE) for the limiting materials of the PBNP-1 and PBNP-2 reactor vessels is projected to fall below 50 ft-lbs by the end of the current license. PBNP has taken credit for analyses performed by the B&W Owner's Group (BWOG) that demonstrate equivalent margins against ductile fracture to those required by 10 CFR 50, Appendix G, through the end of the current license. These analyses will be evaluated to determine whether they will continue to be valid until the end of license extension, revised as necessary to extend their applicability to the end of license extension, or other actions will be taken to ensure USE remains adequate.

To further refine the predictions of the material properties at the end-of-extended life (corresponding to 60 calendar years), an additional surveillance capsule containing materials that closely match the limiting materials in the reactor vessel beltline of both PBNP-1 and PBNP-2, has been installed in PBNP-2. This capsule will be withdrawn after it has received a fluence equivalent to the vessel fluence at 60 calendar years.

B2.1.19 Steam Generator Integrity Program

Program Description

The Steam Generator Integrity Program incorporates the guidance of NEI 97-06 and maintains the integrity of the steam generators (SG), including tubes, tube plugs or other tube repairs, and various secondary-side internal components. The program manages aging effects through a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures. Component degradation is mitigated by controlling primary and secondary water chemistry. Eddy current testing is used to detect steam generator tube flaws and degradation. Visual inspections are performed to identify degradation of various secondary side steam generator internal components.

Aging effects are managed by a combination of U-tube eddy current testing (ECT), secondary-side inspections, sludge lancing, primary to secondary leakage monitoring, and strict water chemistry control. The program credits the Water Chemistry Control Program for primary and secondary water chemistry control. The program also satisfies ASME Section XI, IWB-2500, Category B-Q requirements to perform volumetric examinations of SG tubes.

The overall program is administered in accordance with NEI 97-06, “Steam Generator Program Guidelines,” which is more restrictive than the plant Technical Specifications. For example, NEI 97-06 limits RCS leakage to 150 gallons per day (GPD) while the plant Technical Specification allowable leakage is 500 GPD in any one SG.

SG tubes not meeting the Technical Specification limits for continued operation are removed from service by installation of tube plugs. This plug installation redefines the reactor coolant pressure boundary and loss of SG tube plug integrity can impact the ability of the SG to perform its intended function if permitted to continue without corrective action. Tube plugs installed in the Point Beach SGs are fabricated from heat treated Inconel Alloy 690 material. Although these plugs have a high resistance to primary water stress corrosion cracking (PWSCC), they are routinely inspected as part of the Steam Generator Integrity Program.

A tube integrity assessment is done following each SG tube inspection. The purpose of the assessment is to ensure that the performance criteria have been met for the previous operating period and will continue to be met for the next period. NRC reporting requirements are in accordance with plant Technical Specifications and NEI 97-06.

Periodic visual inspections of accessible areas are performed to verify the integrity of secondary-side components and to assess tube fouling. The inspections include the upper tube bundle, tube support plates, swirl vane, moisture separator, and feed ring areas.

NUREG-1801 Consistency

The Steam Generator Integrity Program is an existing program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M19, “Steam Generator Tube Integrity,” with regards to managing the aging effects of SG tubes, and tube plugs or other tube repairs (Reference 3). The Steam Generator Integrity Program is also an existing plant-specific program that consists of the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” for managing the aging effects of various steam generator secondary-side internal components.

Exceptions to NUREG-1801

None

Enhancements

Enhancements to the Steam Generator Integrity Program include plant procedure revisions to specify the inspections of additional secondary-side components, provide acceptance criteria, and improve the inspection documentation. Plant procedures will also be revised to require an evaluation of the effectiveness of the sludge lancing or the basis for deferral. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Steam Generator Integrity Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M19, “Steam Generator Tube Integrity,” with regards to SG tubes and tube plugs or other tube repairs, is also provided below. An evaluation of each key element against the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” was also conducted with regards to the aging management activities associated with the SG secondary-side components not within the scope of the NUREG-1801 program.

Scope of Program

The Steam Generator Integrity Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Steam Generator

The Steam Generator Integrity Program ensures that SG integrity is maintained under normal operating, transient, and postulated accident conditions. The program is structured to meet NEI 97-06, “Steam Generator Program Guidelines,” and applicable plant Technical Specifications. The program also includes the inspections of various secondary-side internal components, including those important for ensuring tube integrity.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

The program includes measures to mitigate degradation related to corrosion by controlling primary and secondary water chemistry, as described in the Water Chemistry Control Program. The program is structured to meet NEI 97-06, which includes guidelines for foreign material exclusion to inhibit fretting and wear degradation. Periodic sludge lancing is also performed to minimize pitting of the outside diameter of the SG tubes due to oxidizing conditions in the sludge piles.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The SG tube volumetric inspection technique (e.g., ECT) detects flaw size and depth, or, alternatively, remaining tube wall thickness. In addition, the SG tube inspections are performed in accordance with the requirements of the plant Technical Specifications and NEI 97-06. Primary-to-secondary leakage is monitored to verify tube integrity during plant operation. SG tube integrity is assessed against the performance criteria provided in NEI 97-06. The performance criteria include structural integrity, accident-induced leakage and operational leakage limits. Inspection activities also monitor for leakage from the tube plugs. Secondary-side visual inspections of those components within the scope of the program are performed.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

The program complies with the applicable plant Technical Specifications and NEI 97-06. The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws do not exceed established performance criteria. Uncertainties associated with tube inspections, such as probability of detection of certain flaws and uncertainty in flaw sizing, as well as flaw growth rates, are accounted for when performing tube integrity assessments. Monitoring primary-to-secondary leakage during plant operation will identify flaw propagation caused by age-related degradation. Periodic visual inspections of the secondary-side components provides reasonable assurance that degradation will be detected before the loss of any intended function or the integrity of the SG tubes is challenged.

Enhancements to plant procedures will be made to include:

1. Visual inspection(s) for erosion/corrosion of J-tubes, feed rings, pre-moisture separators, and feedwater nozzles,
2. Evaluation of the sludge and sludge removal process to ensure the proposed cleaning is effective,
3. Criteria for non-performance of secondary-side tube sheet cleaning (including specific justification for pitting corrosion concerns),
4. Acceptance criteria for inspections and evaluations, and
5. A requirement to document the condition of the secondary-side of the SGs and assess the program effectiveness.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

Required inspection intervals based on Technical Specification requirements and NEI 97-06 are expected to provide timely detection of tube degradation. Monitoring of primary-to-secondary leakage will also identify degradation of the SG tubing. In addition, condition monitoring assessments are performed after each inspection to determine whether leakage criteria have been satisfied. Operational assessments are performed to verify that structural and leakage integrity are maintained during the operating interval until the next required inspection. The results of the secondary-side component inspections are documented, evaluated, and compared with previous inspection results in order to monitor any on-going degradation such that corrective action would occur prior to any loss of intended function or challenge to tube integrity.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

The acceptance criteria for SG tubes are in accordance with the plant Technical Specifications and NEI 97-06. Loose parts or foreign objects that are found are removed from the SGs unless it is shown by evaluation that these objects will not cause unacceptable tube damage.

Tube inspections are followed by assessments of tube integrity relative to performance criteria. These performance criteria address three areas of tube integrity performance: structural integrity, operational leakage integrity, and accident induced leakage integrity. These performance criteria are expressed in terms of parameters that are directly measurable or that may be calculated on the basis of direct measurements.

When SG tubes do not meet the acceptance criteria specified in the plant Technical Specifications or NEI 97-06, they are repaired or removed from service by plugging. In addition, any detected tube plug leakage requires that the tube plug be repaired or replaced. WCAP-12244 and WCAP-12245 are not applicable to the tube plugs used at PBNP.

The acceptance criteria for allowable primary-to-secondary leakage is in accordance with the NEI 97-06 guidelines, which are more restrictive than the plant Technical Specifications. The acceptance criteria for secondary-side internal components are delineated in the applicable program implementing documents.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Steam Generator Integrity Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

The Steam Generator Integrity Program has been effective in ensuring the timely detection and correction of the aging effects loss of material and cracking. 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 the management of SG tubes, tube plugs or other tube repairs, and various secondary-side internal components.

Supplement 1 of NRC Information Notice (IN) 2002-21 discusses Outside Diameter SCC (ODSCC) found in Alloy 600 SG tubes at Seabrook. The ODSCC at Seabrook was caused by high residual stresses resulting from non-optimal tube processing and could generically affect mill-annealed Alloy 600, thermally treated Alloy 600, or thermally treated Alloy 690 SG tubes. PBNP Unit 1 SGs have thermally treated Alloy 600 tubes. The tubes in the Unit 2 SGs are thermally treated Alloy 690.

The most recent Unit 1 SG inspection results indicate that they are in very good condition. Only 10 of the 6,428 heat transfer tubes have been plugged (each generator has 3,214 tubes). Four (4) were preventively plugged prior to service. Four (4) tubes have been plugged because of wear at the anti-vibration bars (AVB), and two (2) tubes were plugged as a result of damage sustained during modifications to the secondary-side hand holes. No tubes have been plugged because of corrosion type degradation, which is consistent with the experience of all other SGs with thermally treated Alloy 600 heat transfer tubes.

The most recent Unit 2 Steam Generators inspection results indicate that they are also in very good condition. Only 4 of the 6,998 heat transfer tubes have been plugged (each generator has 3,499 tubes). All four were plugged as a precautionary measure, two (2) as a result of shallow (approximately 10% through wall) wear type volumetric indications at the top of the tube sheet, and two (2) as a result of excessive tube noise in the eddy current signal. No tubes have been plugged because of corrosion type degradation. The conclusion of the report stated that there are no active degradation mechanisms in the Point Beach Unit 2 SGs. The absence of detectable corrosion in the SG tubes is consistent with the experience of all other SGs with Alloy 690 heat transfer tubes.

Secondary-side inspections of the current SGs to date have revealed no degradation of the swirl vane, moisture separator, feed ring areas, J-Tubes, or tube support plates. There has been no evidence of wrapper drop on any of the SGs.

The current SG inspection activities have also been evaluated against industry recommendations provided by the Electric Power Research Institute (EPRI) and the SG Original Equipment Manufacturer (OEM), Westinghouse. The overall effectiveness of the Steam Generator Integrity Program is supported by the excellent operating experience and favorable inspection results.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Steam Generator Integrity Program. The current Steam Generator Program has been reviewed by the NRC during several inspections and no deviations or violations have been identified. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Steam Generator Integrity Program provides reasonable assurance that aging effects will be managed such that the SGs will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. The Steam Generator Integrity Program is administered in accordance with the plant Technical Specifications and NEI 97-06, which has had extensive industry and NRC review. This program is all-inclusive in the management of SG tubes, tube plugs or other tube repairs, and various secondary-side internal components.

Results of previous SG inspections and the assessment of potential SG aging mechanisms are described in detail in SG degradation assessment documents. These documents provide a discussion of the design features present in the PBNP SGs that minimize the potential for rapid SG degradation. These design features, in addition to the currently specified inspections, ensure that the SGs intended functions will be maintained for the period of extended operation.

B2.1.20 Structures Monitoring Program

Program Description

The Structures Monitoring Program manages the aging effects associated with steel (including fasteners), concrete (including masonry block and grout), earthen berms, and elastomers. The environments include below grade and fluid exposed material, outdoor weather, and indoor air. The program includes all safety related buildings, structures within the containment, other buildings within the scope of license renewal, crane bridge and trolley structures, and component supports (including HELB structures, panels, etc.) within the scope of license renewal. The program provides for periodic visual inspections and examination of accessible surfaces of the structures and components and identifies the aging effects that impact the materials of construction.

Of the various mechanisms for concrete degradation, only cavitation and abrasion of concrete exposed to flowing water (i.e., water intake/discharge structures) are considered to be of sufficient significance to require aging management. However, this program also provides for comprehensive management of other various potential degradation mechanisms for the concrete structures within the scope of this program.

The Bolting Integrity Program credits this program for the inspection of all structural and component support bolting within the scope of license renewal that is not within the scope of the ASME Section XI, Subsection IWF Inservice Inspection Program or the Systems Monitoring Program. Bolting associated with the supports for electrical cabinets, conduits and cable trays is also included within the scope of this program. Visual inspections of bolting are performed concurrent with the structure inspection. The visual inspections check for corrosion, cracking, missing or loose fasteners, and coating degradation.

NUREG-1801 Consistency

The Structures Monitoring Program is an existing program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.S5, “Masonry Wall Program,” and XI.S6, “Structures Monitoring Program,” and is consistent with, but includes exceptions to, Sections XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants,” and XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Parameters Monitored or Inspected

Enhancements

Enhancements to the Structures Monitoring Program include revisions to existing implementing documents to perform specific inspections related to aging effects, indicate the parameters to be monitored, and provide acceptance criteria. New implementing procedures will be created and/or existing procedures revised to include those components not presently inspected. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Structures Monitoring Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Sections XI.S5, “Masonry Wall Program,” XI.S6 “Structures Monitoring Program,” XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants,” and XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems,” is also provided below.

Scope of Program

The Structures Monitoring Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

13.8 KV Switchgear Building Structure	Facade Unit 1/2 Structure
Circulating Water Pumphouse Structure	Fuel Oil Pumphouse Structure
Component Supports Commodity Group	Gas Turbine Building Structure
Containment Unit 1/2 Building Structure	Primary Auxiliary Building Structure

Control Building Structure	Turbine Building Unit 1/2 Structure
Cranes, Hoists, and Lifting Devices	Yard Structures
Diesel Generator Building Structure	

The Structures Monitoring Program provides inspection requirements to manage aging effects in accordance with the license renewal rule. The scope of the program includes the following:

- Masonry walls identified as performing intended functions in accordance with NRC IEB No. 80-11.
- Structures, including all safety related buildings and structures within containment.
- Circulating water pumphouse.
- Containment, Auxiliary Building, Turbine Hall and G03/G04 overhead cranes.
- Structural steel and fasteners.
- Earthen berm installed around the above ground fuel oil storage tanks.

This element is consistent with the corresponding NUREG-1801, Sections XI.S5, XI.S6, and XI.M23 aging management program elements.

This element includes exceptions to the corresponding NUREG-1801, Section XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power,” aging management program element. NUREG-1801, Section XI.S7 includes water and intake structures as described in RG 1.127. PBNP has not committed to RG 1.127 and does not include the intake crib, intake pipes or discharge flume within the scope of license renewal. The inspections performed on the circulating water pumphouse are in general agreement with RG 1.127.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

There are no preventive actions associated with this program. This is an inspection and monitoring program.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Parameters Monitored or Inspected

Visual inspections are used to inspect the structures and components that are within the scope of the Structures Monitoring Program. The following parameters are monitored or inspected:

- For masonry wall inspections, the parameters monitored are cracking, deteriorated penetrations, or broken block.
- For concrete structures, the parameters inspected are selected to ensure that aging degradation will be detected and the extent of degradation can be determined. The parameters monitored are cracking and deterioration. The deterioration may include concrete dissolution, pitting, popouts, spalling, erosion, abrasion, water seepage, differential settlements, and rust stains.
- For concrete with embedments, the concrete areas around the embedment are inspected (in addition to the parameters above) for corrosion or corrosion stains from the embedded metal, detached embedment or loose bolts, and concrete degradation due to vibratory loads.
- For concrete surfaces lined by metallic or plastic liners (e.g., Spent Fuel Pool), the parameters monitored include corrosion, cracking, leakage, and bulges or depressions in the liner plate.
- For structural steel component supports, the program monitors for overall misalignment, deflection, distortion, twisting, cracking, corrosion, missing or loose fasteners/anchors, missing/degraded grout under the base plates, and cracked welds.
- For water control structures (i.e., circulating water pumphouse) the parameters monitored include cracking, movements (e.g., settlement, deflection, heaving), loss of material due to abrasion or cavitation, seepage, and leakage.
- For the cranes within the scope of license renewal, the inspections include structural bolting, rail wear, and corrosion of structural components of the bridge and trolley.
- Structural bolting is inspected for indications of potential problems including signs of corrosion, pitting, cracking, rust, empty holes, looseness, physical damage or deformation, full thread engagement of nuts, missing or out of place parts, elongated or oversized bolt holes, proper washers, proper stud alignment into the building structure, and coating degradation.

- The earthen berm installed around the above ground fuel oil storage tanks is inspected for signs of physical damage such as loss of material due to surface run-off and erosion.

This element is consistent with the corresponding NUREG-1801, Sections XI.S5, XI.S6, and XI.S7 aging management program elements.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems,” aging management program element. NUREG-1801 states that the number and magnitude of lifts made by the crane are reviewed. PBNP does not keep records of the number and magnitude of lifts that have been made, however PBNP uses the cranes for the functions they were designed to perform and the cranes are periodically inspected. Crane usage is well within the design capacity and service duty of the cranes. Any lifts in excess of rated crane capacity would be evaluated and documented per ANSI B30.2.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Detection of Aging Effects

For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended function(s). For example:

- Visual inspections by qualified inspection personnel are used to examine masonry walls. The inspection interval is 12 months.
- Visual inspections are also used to detect degradation of water control structures (i.e., circulating water pumphouse). The inspection interval is 5 years, however portions of the forebay are inspected every refueling by divers.
- Accessible structural bolting is inspected by visual examination. These inspections are conducted on a 12-month cycle.
- Crane rails and structural components for heavy load and light load handling equipment within the scope of the program, are visually inspected for degradation annually (18 months for containment cranes and lift rigs). Functional tests are also performed.

- Visual examinations of concrete surfaces for evidence of cracking and deterioration are performed annually. The deterioration may include popouts, spalling, erosion/abrasion, rust stains, scaling, and differential settlement.
- The earthen berm installed around the above ground fuel oil storage tanks is visually inspected for signs of physical damage. These visual inspections are performed annually.

Enhancements include revisions to existing implementing documents to perform specific inspections related to aging effects, indicate the parameters to be monitored, and provide acceptance criteria. For example, enhancements will be made to include:

- Specific guidance on corrosion and crane rail wear evaluation and acceptance criteria.
- Steps to inspect the trolley and bridge structural components for signs of corrosion, rail wear, or other discrepancies and add a step to provide the acceptance criteria for the structural component inspections.
- Steps to provide inspection acceptance criteria. Guidance for acceptance criteria can be found in Regulatory Guide 1.127, Section C, Paragraph 2.

In addition, new implementing procedures will be created and/or existing procedures revised to include those components not presently inspected.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Monitoring and Trending

Monitoring and trending of structural and component material condition is performed as described below.

- NUREG-1801, Section XI.S5 states that trending is not required for masonry walls, monitoring is achieved by periodic inspections for cracking.
- For structures, monitoring and trending is achieved when responsible engineers review the reports and compare the latest examination reports with the previous reports. If the performance criteria in plant procedures is not met, the structure will be evaluated to determine if the structure can still perform its required function in accordance with 10 CFR 50.65(a)(1). Annual monitoring reports generated under the program prioritize any needed corrective action.

- Water control structures are monitored by periodic inspections and evaluations of the inspection results. As previously stated, the circulating water pumphouse is inspected to verify that it will continue to perform its intended function of being able to provide water flow from the ultimate heat sink.
- NUREG-1801, Section XI.M23 states that monitoring and trending are not required as part of the crane inspection program.
- The earthen berm installed around the above ground fuel oil storage tanks is monitored by periodic inspections and evaluations of the inspection results. These inspections verify that the earthen berm will continue to perform its intended function of containing fuel oil spills and any resulting fire.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Acceptance Criteria

For masonry walls, concrete structures, structural steel including bolting and fasteners, water control structures, and crane rails and structural members, documented areas are compared to previously reported conditions to determine the extent of any new degradation or changing condition. If a structure or component does not meet the acceptance criteria stated in the inspection procedure, the structure/component will be evaluated to determine if it can still perform its function as defined by the Maintenance Rule (i.e., support and/or protect maintenance rule systems and equipment during normal operation and design basis events). If the structure is found unable to perform its function, it will be reclassified under the Maintenance Rule as (a)(1).

Any sign of physical damage to the earthen berm around the above ground fuel oil storage tanks is evaluated to determine whether it can still perform its intended function. An unacceptable visual indication is any noted condition or situation that, if left unmanaged, could lead to a loss of the intended function.

Any significant visual indication of loss of material due to corrosion of crane structural members or rail wear is evaluated according to vender recommendations and/or applicable industry good practice and standards.

The examinations and evaluations are conducted by qualified personnel. Any adverse condition or observed degradation determined to be a potential cause of failure or that indicates changing conditions that may lead to an increased degradation rate is documented in the corrective action program.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Administrative Controls

The Structures Monitoring Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Operating Experience

Masonry walls are inspected per plant procedures. Cracks in masonry walls have been found primarily at the mortar joints and these findings have been documented and resolved.

Concrete structure inspections have been and continue to be a large part of the Structures Monitoring Program as described in plant procedures. Cracks, erosion, corrosion of embedded steel, and concrete spalling have been observed. These findings are evaluated and resolved by engineering.

Periodic inspections of the circulating water pumphouse have been an ongoing program. Divers perform inspections during refueling outages. Minor degradation of these concrete structures has been found and recorded. Zebra mussels are periodically removed from the forebay areas.

The structural members of the cranes that are in the scope of this program are inspected. There has been no corrosion related degradation found on these structural components.

No signs of physical damage have been observed on the earthen berm around the above ground fuel oil storage tanks.

Industry operating experience has shown that degradation occurs in structural steel and concrete components. The inspections performed at PBNP as part of the Structures Monitoring Program have revealed that degradation has occurred in both concrete and structural steel components. The inspection results are recorded in an annual report. Any degradation determined to be a potential cause of failure or indicative of changing conditions that may lead to an increased degradation rate are documented in the corrective action program. Evaluation of inspection results will place the structures in one of the following categories:

- Acceptable: Acceptable structures are capable of performing their structural functions, including the protection and support of maintenance rule systems or components. Acceptable structures are free of deficiencies or degradation which could lead to possible failures. Acceptable structures shall be assigned Maintenance Rule (a)(2) status.
- Acceptable with Deficiencies: Structures which are Acceptable with Deficiencies are those which are capable of performing their structural functions, including the protection or support of maintenance rule systems or components, but are degraded or have deficiencies which could deteriorate to an unacceptable condition, if not analyzed or corrected prior to the next scheduled examination. Structures that are Acceptable with Deficiencies should be considered for Maintenance Rule (a)(1) status. If the structure requires repair or more frequent inspections to provide assurance that it will remain functional, Maintenance Rule (a)(1) goal setting should be considered.
- Unacceptable: Unacceptable structures are those which are damaged or degraded such that they are not capable of performing their structural functions. An unacceptable structure should be classified as a functional

failure in accordance with the Maintenance Rule. Structures classified as Unacceptable shall be placed in Maintenance Rule (a)(1) status.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Structures Monitoring Program. A Maintenance Rule assessment was performed by Nuclear Oversight in the first quarter of 2003, which reviewed the structural monitoring portion of the Maintenance Rule as a part of this assessment. The assessment concluded that the overall structural monitoring program was considered acceptable with program enhancements recommended. These enhancements were entered into the corrective action program and resolved. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program elements.

Conclusion

The Structures Monitoring Program provides reasonable assurance that the applicable aging effects will be managed such that structures and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. The Structures Monitoring Program has been effective in maintaining the intended functions of long-lived passive structures and components.

B2.1.21 Systems Monitoring Program

Program Description

The Systems Monitoring Program manages aging effects for normally accessible, external surfaces of piping, tanks, and other components and equipment within the scope of license renewal. These aging effects are managed through visual inspection and monitoring of external surfaces for leakage and evidence of material degradation.

The scope of the Systems Monitoring Program includes visual inspections of the external surfaces of components. The Systems Monitoring Program is credited by the Boric Acid Corrosion Program for the inspection of SSC that do not contain borated water, but may be subject to the degrading effects of borated water leakage. The Systems Monitoring Program is also credited by the Bolting Integrity Program for the inspection of bolting. The

Systems Monitoring Program credits the Tank Internal Inspection Program for the inspection of inaccessible portions of the Condensate Storage Tanks external surfaces (i.e., tank bottoms).

NUREG-1801 Consistency

The Systems Monitoring Program is an existing plant-specific program that consists of the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants.” Since this program includes visual inspections of the external surfaces of carbon steel tanks, the Systems Monitoring Program is also an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M.29, “Above Ground Carbon Steel Tanks” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Preventive Actions
- Detection of Aging Effects
- Monitoring and Trending

Enhancements

Enhancements to the Systems Monitoring Program include revisions to existing implementing documents to strengthen the requirements for system walkdowns, documentation and records retention, and provide inspection guidance. Additionally, the aging effects and mechanisms to be managed will be incorporated into the existing implementing documents. These enhancements are required to satisfy the NUREG-1801 aging management program and Standard Review Plan requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Systems Monitoring Program, are described below. An evaluation of each key element against the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” was conducted. Since this program includes visual inspections of the external surfaces of carbon steel tanks, the results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M.29, “Above Ground Carbon Steel Tanks,” is provided below.

Scope of Program

The Systems Monitoring Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Fire Protection
Chemical and Volume Control	Heating Steam
Circulating Water	Main and Auxiliary Steam
Component Cooling Water	Non-Class 1 RCS Components
Containment Hydrogen Detectors and Recombiners	Plant Air
Containment Isolation Components	Residual Heat Removal
Containment Spray	Safety Injection
Containment Ventilation	Service Water
Emergency Power	Spent Fuel Cooling
Essential Ventilation	Treated Water
Feedwater and Condensate	Waste Disposal

The Systems Monitoring Program is credited for managing the aging effects for normally accessible surfaces of piping, tanks, and other components and equipment within the scope of license renewal. These aging effects are managed through visual inspection and monitoring of external surfaces for leakage and evidence of material degradation.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M.29, aging management program element. The NUREG-1801 program for above ground carbon steel tanks states that the program consists of “preventive measures to mitigate corrosion by protecting the external surfaces of carbon steel tanks protected with paint or coatings.” PBNP does not take credit for any coating or paint for mitigating corrosion even though the tanks may be painted or coated. However, inspections of the coating or paint will provide an indication of the condition of the material underneath the coating or paint.

Therefore, periodic system walkdowns will detect the effects of corrosion if present, which meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

There are no preventive actions associated with this program. The objective of this program is to identify the aging effects of concern before a loss of intended function occurs (i.e., condition monitoring).

This element includes exceptions to the corresponding NUREG-1801, Section XI.M.29, aging management program element. The NUREG-1801 program for above ground carbon steel tanks states that the program consists of “preventive measures to mitigate corrosion by protecting the external surfaces of carbon steel tanks protected with paint or coatings.” PBNP does not take credit for any coating or paint for mitigating corrosion even though the tanks may be painted or coated. However, inspections of the coating or paint will provide an indication of the condition of the material underneath the coating or paint. Therefore, periodic system walkdowns will detect the effects of corrosion if present. Sealant or caulking is not used at the interface edge between the tank and the concrete foundation for the Condensate Storage Tanks and above ground Fuel Oil Storage Tanks. This program credits the Tank Internal Inspection Program for thickness measurements of the inaccessible portions of Condensate Storage Tanks external surfaces (i.e., tank bottoms). Thickness measurements of the bottom of the above ground Fuel Oil Storage Tanks were performed in August of 2000 with no significant loss of material detected.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The program utilizes periodic plant system walkdowns to monitor for leakage and evidence of material degradation. Above ground carbon steel tank external coatings or paint are inspected to provide an indication of the condition of the material underneath the coating or paint. Sealants or caulking at the tank/support structure interface, if used to prevent water intrusion, are also inspected for degradation.

This element is consistent with the corresponding NUREG-1801, Section XI.M.29, aging management program element.

Detection of Aging Effects

The external surfaces of various component types (e.g., pump casings, valve bodies, piping, expansion joints) are visually inspected for leakage and evidence of material degradation, such as loss of material due to corrosion. The outer surfaces of above ground carbon steel tanks are visually inspected for signs of coating or paint degradation to provide an indication of the condition of the material underneath the coating or paint. The sealant or caulking at the tank/support structure interface, if used to prevent water intrusion, is also inspected for degradation. This program credits the Tank Internal Inspection Program for the inspection of inaccessible portions of the Condensate Storage Tanks external surfaces (i.e., tank bottoms). Degradation of bolted connections is detected by visual inspections of the bolted components during system walkdowns. Bolted connections are inspected for missing fasteners and degradation such as damaged threads and evidence of corrosion. The minimum walkdown frequency is once per year for those systems and components that are accessible during normal plant operation. Systems and components that are only accessible during plant outages, are inspected at least once per refueling interval. The inspection frequency may be increased based on the safety significance, production significance, and/or operating experience of each system.

Enhancements to existing implementing documents will be made to include the following:

- Additional Inspections, and
- Strengthen the requirements for performance of system walkdown inspections at a minimum specified frequency (12 months, or refueling intervals for those components not accessible during normal operation). Include requirements for a review, evaluation and approval for any deferred inspections. Require documentation to be retained and retrievable. Require an Action Request be generated if the inspections do not occur within the inspection interval. As an alternative to placing these restrictions in the existing implementing documents, CHAMPS callups may be generated subject to the constraints placed on deferrals, cancellation, and frequency changes for license renewal.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M.29, aging management program element. The exception to the NUREG-1801 program is that thickness measurements of the inaccessible external surfaces (i.e., tank bottoms) of the above ground Fuel Oil Storage

Tanks are not performed. The internals of these tanks were inspected in August of 2000 and no significant rust deposits, corrosion, or other obvious defects were found. Thickness measurements of the bottom of the tanks were performed and indicated no significant loss of material. Subsequent to the inspection and thickness measurements, the tanks were upgraded. The upgrade installed a polyester resin coating on the inside of the tanks, covering the bottoms and extending approximately two feet up the tank walls. Future thickness measurements are not considered necessary or practical, because of potential thickness measurement complications due to the polyester resin coating, and the absence of any significant material loss due to corrosion in over 30 years of service.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Monitoring and Trending

Visual inspections are performed at least once per year for those systems and components that are accessible during normal plant operation. Systems and components that are only accessible during plant outages, are inspected at least once per refueling interval. The inspection frequency may be increased based on the safety significance, production significance, and operating experience of each system. These system walkdown inspections provide for timely detection of aging effects (i.e., prior to a loss of intended function). Walkdown results are also documented to provide a historical record of items monitored during the walkdowns. This program credits the Tank Internal Inspection Program for the inspection of inaccessible portions of carbon steel tank external surfaces, such as tank bottoms.

This element includes exceptions to the corresponding NUREG-1801, Section XI.M.29, aging management program element. As discussed above, the exception to the NUREG-1801 program is that thickness measurements of the inaccessible external surfaces of the above ground Fuel Oil Storage Tanks are not performed.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Acceptance Criteria

An Action Request will be initiated for any discrepancies found that may affect the components ability to perform its intended function (i.e., significant degradation). Other types of degradation are recorded for further evaluation.

When bolted joints for pressure retaining components are observed to have significant degradation or be leaking, corrective actions are taken in accordance with the corrective action program. An Action Request is also initiated for significant degradation of tank coatings or paint, and sealants or caulking (if applicable). Significant degradation consists of cracking, flaking, or peeling of paint or coatings, and cracked sealant or caulking (if applicable). This program credits the Tank Internal Inspection Program for thickness measurements of inaccessible portions of carbon steel tank external surfaces, such as tank bottoms. Thickness measurements will be evaluated against the design thickness.

This element is consistent with the corresponding NUREG-1801, Section XI.M.29, aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801, Section XI.M.29, aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801, Section XI.M.29, aging management program element.

Administrative Controls

The Systems Monitoring Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801, Section XI.M.29, aging management program element.

Operating Experience

Degradation of components that are within the scope of this program has been documented in accordance with plant procedures. Documentation of walkdowns is currently maintained in the system engineer's System Handbooks. This documentation consists of a checklist of components to be inspected, which includes inspections of bolting and the external surfaces of tanks. A corrective Work Order and/or an Action Request is issued if observed component degradation requires repair or further evaluation. A review of documentation for seven systems within the scope of license renewal indicated that these walkdowns usually result in the initiation of corrective Work Orders for the repair of minor leaks from both flanged connections and valve stem packing, degraded grout under pumps, or pipe supports. The system engineers also track the number of open Action Requests and Work Orders for their systems, which gives them an indication of the actions that need to be accomplished in order to improve the condition of their systems.

Thickness measurements of the bottoms of the above ground Fuel Oil Storage Tanks were performed in August of 2000, which indicated no significant loss of material due to corrosion in over 30 years of service.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Systems Monitoring Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801, Section XI.M.29, aging management program element.

Conclusion

The Systems Monitoring Program provides reasonable assurance that aging effects will be managed such that systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. The Systems Monitoring Program has been an ongoing program at PBNP, which has been improved over the years. Additionally, the Systems Monitoring Program supports implementation of the Maintenance Rule (10 CFR 50.65).

System engineers, plant operators, maintenance personnel, and others have and will continue to report conditions which could effect the safe operation of the plant and personnel safety. These conditions are documented in the form of Work Orders, Action Requests, or inspection procedures. This is demonstrated by the number of Action Requests and Work Orders initiated each year.

B2.1.22 Tank Internal Inspection Program

Program Description

The Tank Internal Inspection Program is a new plant-specific program that manages aging effects on the (a) internal surfaces of carbon steel tanks, and (b) inaccessible external surfaces of carbon steel tanks (i.e., tank bottoms) where wall thickness measurements may be taken from inside the tank to detect external degradation (e.g., using ultrasonic techniques).

This program provides for periodic inspections to confirm that aging effects will not impair tank intended functions. Tank wall thinning of internal surfaces may be detected by direct visual inspection from inside the tank or indirectly by UT wall thickness measurements from outside the tank. Tank wall thinning of external surfaces that are inaccessible (e.g., bottom of tanks that sit directly on the ground or other support structures) will be detected by UT wall thickness measurements from inside the tank.

This program is credited by the Systems Monitoring Program for thickness measurements of the bottom of carbon steel tanks that are sitting directly on the ground or other structures such that external inspection of all surfaces is not possible.

Enhancements

Enhancements to the Tank Internal Inspection Program include the revision of existing and/or creation of new implementing document(s) for this new program. The revised and/or new document(s) will define program responsibilities, describe inspection and evaluation methodology, provide acceptance criteria, and provide the inspection schedule. Included in the implementing document(s) will be provisions for adjusting the inspection scope and/or frequency based on the results of previous inspections and operating experience. The implementing document(s) will also cause corrective actions to be taken if the acceptance criteria is not met or if there is any significant degradation of carbon steel tank internal coatings.

This new program is scheduled for implementation prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Tank Internal Inspection Program, are described below. An evaluation of each key element against the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” was conducted.

Scope of Program

The Tank Internal Inspection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Emergency Power

The Tank Internal Inspection Program is credited for managing the aging effect loss of material due to corrosion on the internal and inaccessible external surfaces (i.e., tank bottoms) of carbon steel tanks. Periodic inspections will determine the extent of corrosion occurring in the subject tanks.

Preventive Actions

If internal tank surfaces are coated to prevent corrosion, the inspections performed under this program will assess the condition of the internal coating. Coatings are not credited for license renewal, but inspection of the coating will provide an indication of the condition of the material underneath the coating.

Parameters Monitored or Inspected

The internal surfaces of carbon steel tanks will be periodically visually inspected for the existence of corrosion. Wall thinning may be detected by UT thickness measurements from outside the tank. The inaccessible external surfaces of carbon steel tanks (i.e., tank bottoms) will be inspected by UT wall thickness measurements from inside the tank to detect wall thinning due to corrosion of the external surfaces.

Detection of Aging Effects

The presence of corrosion that could lead to a loss of material will be determined by periodic visual inspections of the internal surfaces of the carbon steel tanks. Internal surfaces will be examined for flaking, blistering, discoloration, pitting, corrosion, or other signs of age-related degradation that could lead to a loss of material. Wall thinning may be detected by UT thickness measurements from outside the tank. The inaccessible external surfaces of carbon steel tanks (i.e., tank bottoms) will be periodically inspected by UT wall thickness measurements from inside the tank to detect wall thinning due to corrosion of the external surfaces. The inspection scope and frequency will be adjusted based on the results of previous inspections and operating experience.

Enhancements to the implementing documents for the Tank Internal Inspection Program shall define the program responsibilities, describe the inspection and evaluation methodology, provide acceptance criteria, and provide the inspection schedule. Included in the implementing document(s) will be provisions for adjusting the inspection scope and/or frequency based on the results of previous inspections and operating experience. Corrective actions shall be taken whenever the acceptance criteria is not met or if there is any significant degradation of carbon steel tank internal coatings.

Monitoring and Trending

Corrosion of carbon steel tank internal and inaccessible external surfaces will be monitored and trended if significant material loss is detected.

Acceptance Criteria

Any degradation of carbon steel tank internal surfaces will be recorded and evaluated to ensure minimum wall thickness is maintained until the next scheduled inspection. Thickness measurements of inaccessible tank bottoms and walls are evaluated against the design thickness.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

Administrative Controls

The Tank Internal Inspection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B (Reference 2) and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

Operating Experience

A review of plant operating experience revealed that the south Condensate Storage Tank was internally inspected in January 2000 with minor surface rust observed on the floor of the tank and corrosion through the tank coating observed on the lower 6 to 8 inches of the tank wall. A Condition Report was issued for engineering to evaluate the condition of the tank coating and to inspect and evaluate the north Condensate Storage Tank for similar conditions. The inspection of the north Condensate Storage Tank revealed minor surface rust similar to that found in the other tank. Both tanks were evaluated by engineering, cleaned and returned to service.

The Emergency Diesel Generator starting air receivers for G01 and G02 are pressure vessels, which are periodically inspected in accordance with Wisconsin Administrative Code requirements. Visual inspections and UT thickness measurements were performed on these starting air receivers in 2002 and 2003, which indicated no adverse conditions.

A review of industry operating experience revealed that a coated carbon steel Refueling Water Storage Tank (RWST) was found to have coating degradation. The coating was used to protect the carbon steel from corrosion caused by contact with borated water. This operating experience does not apply to PBNP, because the RWSTs at PBNP are constructed of stainless steel. As mentioned above, the interior coated surfaces of the Condensate Storage Tanks were found to have minor corrosion. A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Tank Internal Inspection Program.

As additional operating experience is obtained, lessons learned may be used to adjust this program.

Conclusion

The Tank Internal Inspection Program will provide reasonable assurance that loss of material due to corrosion will be managed such that carbon steel tanks within the scope of the program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. This is a new program that will use techniques with a demonstrated capability and proven industry record to detect corrosion. Tank wall thinning due to corrosion of external surfaces that are inaccessible (e.g., bottoms of tanks that sit directly on the ground or other support structures) will be detected by UT wall thickness measurements from inside the tank.

B2.1.23 Thimble Tube Inspection Program

Program Description

The Thimble Tube Inspection Program is an existing plant-specific program that manages aging effects for incore instrument thimble tubes. This program requires periodic eddy current testing of thimble tubes and contains criteria for determining sample size, inspection frequency, flaw evaluation, and corrective action, in accordance with NRC Bulletin 88-09.

The wear of thimble tubes results in degradation of the RCS pressure boundary and can also create a potentially non-isolable leak of reactor coolant. Thus, loss of material due to wear can impact the ability of the thimble tube's pressure boundary to perform its intended function if permitted to continue without corrective action.

In response to NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors,” PBNP established a program for inspection and assessment of thimble tube thinning requiring periodic Eddy Current Testing (ECT) inspections on each unit. The results demonstrate that the thimble tubes experience loss of material due to wear and that ECT discovers the worn tube prior to a leak occurring. For example, 5 tubes have been replaced in Unit 1 due to wear since 1985. One of these 5 tubes had been capped, one other showed significant wear and would require repositioning or capping prior to the next inspection, while the other 3 were replaced since they indicated the most wear when compared to the remaining tubes. These 3 tubes were not at minimum wall thickness nor did calculations indicate that they would be at minimum wall thickness before the next inspection. It was simply more convenient to replace them at this time since the job set up was already accomplished. The Unit 1 thimble tubes were last ECT during the 2001 refueling outage and the lowest estimated tube life was 6.13 years. The Unit 2 thimble tubes were repositioned during the 1999 refueling outage and were last ECT during the 2000 refueling outage.

For a typical tube, wear will be localized resulting in a large volume of sound tube material surrounding the worn area. Consequently, to prolong the life of thimble tubes experiencing wear, the tube may be repositioned to move the worn area away from the lower core plate. This will move the degraded portion of the tube into an area where wear is not occurring and place intact tube material in the area where wear is occurring. By doing this, the thimble tube life can be extended without undue risk of failure. The repositioning of tubes will be evaluated on a case-by-case basis. To ensure that a tube failure does not occur between inspections, tubes exhibiting a wall loss of 60% will be capped and taken out of service.

The frequency of inspections is based on the maximum wall loss noted in a region of active wear and the projected wear which would occur based on a known wear rate. All 36 thimble tubes are inspected using eddy current testing each inspection cycle. Inspections are conducted in accordance with Section V of the ASME Boiler and Pressure Vessel Code, 1980 Edition, Winter 1981 Addenda.

Enhancements

Enhancements to the Thimble Tube Inspection Program include correction of program deficiencies that have previously been identified and documented in the corrective action program. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Thimble Tube Inspection Program, are described below. An evaluation of each key element against the appropriate ten elements described in Branch Technical Position RLSB-1, “Aging Management Review-Generic,” which is included in Appendix A of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” was conducted.

Scope of Program

The Thimble Tube Inspection Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Reactor Vessel Internals	Reactor Vessel

The scope of this program includes the Unit 1 and 2 flux map thimble tubes, which are part of the RCS pressure boundary. This program manages the aging effect of loss of material due to wear. The program utilizes ECT to determine thimble tube wall thickness and predict wear rates for the early identification of potential thimble tube failures. All thimble tubes on both units are periodically inspected.

Preventive Actions

The evaluation of the remaining thimble tube wall thickness obtained from the ECT will be used to predict the remaining life of the thimble tubes and to take corrective action before failure occurs. Thus, by performing ECT and using conservative methods to calculate the remaining thimble tube wall thickness and life, the intended function of the tubes will be maintained until the next scheduled inspection.

Parameters Monitored or Inspected

Thimble tube wall thickness is monitored through periodic inspections.

Detection of Aging Effects

The aging effect of loss of material due to wear is detected by periodic ECT of thimble tubes. One hundred percent of the thimble tubes are ECT each inspection cycle. The data will be evaluated and remaining wall tube thickness will be calculated along with the remaining years of life expectancy. In addition, the next inspection cycle will be determined and take place prior to expiration of the calculated expected life. This will ensure that no leaks occur due to wear of a thimble tube. PBNP has not experienced any thimble tube leaks, thus the program has proven effective in detecting tubes that have experienced wear. Tubes that were found to have wear approaching life expectancy have been replaced, repositioned or capped.

Enhancements to the Thimble Tube Inspection Program include correcting program deficiencies concerning inspection deferrals, calculation methodology, and document retention.

Monitoring and Trending

Inspection, monitoring and trending activities are described in plant implementing documents. ECT results indicate the location and extent of wear on each thimble tube. These results are compared to previous ECT results. Therefore, wear rates and locations are available for further evaluation and used to schedule the next inspection.

Acceptance Criteria

The acceptance criteria for thimble tube wall thinning is that tubes will be capped if their indicated wall loss plus the predicted wall loss between inspections exceeds 60%. This is a conservative figure, since calculations show that a tube would have to wear 83% of wall tube thickness prior to failing and causing a leak. The 83% loss of wall tube failure determination was also conservatively calculated, since it assumes even wear around the tube and wear does not occur evenly around a tube, but is localized. Therefore, the acceptance criteria chosen for PBNP ensures that no leaks will occur in the thimble tubes prior to the next inspection.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

Administrative Controls

The Thimble Tube Inspection Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

Operating Experience

The original incore thimble tubes were replaced in 1985 for Unit 1 and in 1984 for Unit 2. It was necessary to replace the original thimble tubes due to internal blockages. No leaking incore thimble tubes were discovered during the first 13 years of operation. The replacement tubes are made of Type 316 stainless steel with a nominal outside diameter of 0.313 inches and a nominal inside diameter of 0.210 inches.

NRC Bulletin 88-09 was issued in response to the thinning of thimble tubes experienced at several Westinghouse pressurized water reactors. The Thimble Tube Inspection Program at PBNP was initiated in response to that bulletin. As a result of inspections performed by the program, 5 tubes on Unit 1 have been replaced due to wear since 1985. One of these 5 tubes had been capped, one other showed significant wear and would require repositioning or capping prior to the next inspection, while the other 3 were replaced since they indicated the most wear when compared to the remaining tubes. These 3 tubes were not at minimum wall thickness nor did calculations indicate that they would be at minimum wall thickness before the next inspection. It was simply more convenient to replace them at this time since the job set up was already accomplished.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Thimble Tube Inspection Program. Problems have recently been identified by the program owner regarding inspection deferrals, calculation methodology, and records retention associated with the Thimble Tube Inspection Program. These problems have been entered into the corrective action program and will be resolved to ensure the overall effectiveness of the program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

Conclusion

The Thimble Tube Inspection Program provides reasonable assurance that the aging effect loss of material due to wear will be managed such that the thimble tubes will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation. Thimble tube wear results from flow induced vibration and can be detected by eddy current testing. This technique has been successfully used throughout the industry for many years to detect wall thinning in thimble tubes and heat exchanger tubes. It has been used to monitor thimble tubes at

PBNP for over ten years and has resulted in replacement of a small number of thimble tubes due to wear. However, there have been no instances of through wall thimble tube leakage at PBNP.

B2.1.24 Water Chemistry Control Program

Program Description

The Water Chemistry Control Program manages aging effects by controlling the internal environment of systems and components. Primary, borated and secondary water systems are included in the scope of the program. The program conforms to the guidelines in EPRI TR-105714 (Reference 18) and TR-102134 (Reference 19). The aging effects are managed by controlling concentrations of known detrimental chemical species such as halogens, sulfates and dissolved oxygen below the levels known to cause degradation. The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of water chemistry. For low-flow or stagnant portions of a system, a one-time inspection of selected components at susceptible locations provides verification of the effectiveness of the Water Chemistry Control Program. No verification inspections are required for intermediate and high flow regions.

The objective of the Water Chemistry Control Program is to protect the integrity, reliability and availability of systems and components. Thus, the Water Chemistry Control Program manages the water chemistry in plant systems to ensure that water quality is compatible with the materials of construction and to minimize corrosion of internal surfaces exposed to corrosive environments.

The Water Chemistry Control Program is credited for managing aging effects such as loss-of-material due to general, pitting and crevice corrosion, MIC, cracking due to SCC, and fouling due to corrosion product buildup in stagnant and low flow regions, by controlling the environment to which internal surfaces of systems and components are exposed. The aging effects are minimized by controlling the chemical species that cause the underlying mechanisms that result in these aging effects. The program provides assurance that an elevated level of contaminants and oxygen does not exist in the systems and components covered by the program, and thus minimizes the occurrences of aging effects. The program conforms to the guidelines in EPRI TR-105714, Rev. 4, and TR-102134, Rev. 5. The One-Time Inspection Program verifies that the Water Chemistry Control Program is managing the effects of aging in low flow or stagnant areas.

PBNP deviates slightly from the control parameters contained in EPRI TR-102134-Rev. 5, “PWR Secondary Water Chemistry Guidelines.” During startup conditions with the RCS >

200 degrees F but < 5% reactor power, EPRI requires that hydrazine in the steam generator feedwater source be maintained > 100 ppb (or > 8 x [O2], whichever is higher). PBNP does not have the capability for maintaining a continuous hydrazine feed at these conditions. Alternatively, PBNP makes batch additions of hydrazine to the steam generators through the auxiliary feedwater system to maintain detectable hydrazine levels in the steam generator blowdown. This provides assurance that there is little dissolved oxygen in the steam generator bulk water supply to contribute to corrosive conditions.

NUREG-1801 Consistency

The Water Chemistry Control Program is an existing program that is consistent with, but includes exceptions to, NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M2, “Water Chemistry” (Reference 3).

Exceptions to NUREG-1801

See the following element discussions for elaboration on the exceptions to the NUREG-1801 aging management program element assumptions:

- Scope of Program
- Parameters Monitored or Inspected

Enhancements

Enhancements to the Water Chemistry Control Program include revisions to existing implementing procedures to include the applicable aging effects. Procedures will also be revised to require additional sampling after corrective actions have been taken, whenever a parameter is not within the specified value and continuous monitoring is not available. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Water Chemistry Control Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section XI.M2, “Water Chemistry” is also provided below.

Scope of Program

The Water Chemistry Control Program consists of PBNP activities that manage the aging effects for components in the following systems and structures:

Auxiliary Feedwater	Non-Class 1 RCS Components
Chemical and Volume Control	Pressurizer
Class 1 Piping/Components	Primary Auxiliary Building Structure
Component Cooling Water	Reactor Vessel
Containment Isolation Components	Reactor Vessel Internals
Containment Spray	Residual Heat Removal
Containment Unit 1/2 Building Structure	Safety Injection
Feedwater and Condensate	Spent Fuel Cooling
Heating Steam	Steam Generator
Main and Auxiliary Steam	Waste Disposal

The Water Chemistry Control Program manages aging effects such as loss of material due to general, pitting and crevice corrosion, MIC, cracking due to SCC, and fouling buildup for the internal surfaces of components in both the primary and secondary systems. The program accomplishes this task by monitoring and controlling known detrimental contaminants such as chlorides, fluorides, dissolved oxygen and sulfate concentrations for water chemistry in accordance with the EPRI Guidelines TR-105714, for primary water chemistry, and TR-102134 for secondary water chemistry. The program includes sampling activities for primary, borated, and secondary water systems.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 states that the water chemistry control is in accordance with EPRI report TR-105714, Rev. 3 for primary water chemistry, and TR-102134, Rev. 3 for secondary water chemistry. PBNP has adopted to use TR-105714, Rev. 4 and TR-102134, Rev. 5 which are later revisions of the same documents.

The Revision 4 changes to TR-105714 consider the most recent operating experience and laboratory data. It reflects increased emphasis on plant-specific optimization of primary water chemistry to address individual plant circumstances and the impact of the Nuclear Energy Institute (NEI) steam generator initiative, NEI 97-06, which requires utilities to meet the intent of the EPRI Guidelines. TR-105714, Rev. 4 attempts to clearly distinguish between prescriptive requirements and non-prescriptive guidance. Specific Revision 4 changes that may cause a deviation from the NUREG-1801 element discussion are addressed in the applicable element.

Revision 4 of TR-102134 was issued in November 1996 and provided an increased depth of detail regarding the corrosion mechanisms affecting steam generators and the balance of plant, and also provided additional guidance on how to integrate these and other concerns into the plant-specific optimization process. Revision 5 provides additional details regarding plant-specific optimization and clarifies which portions of the EPRI Guidelines are mandatory under NEI 97-06. Specific Revision 4 or Revision 5 changes that may cause a deviation from the NUREG-1801 element discussion are addressed in the applicable element. Exceptions are justified based on current EPRI guidance.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Preventive Actions

NUREG-1801 states: “The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry.” The specifications, sampling and analysis frequencies, and corrective actions are discussed in the applicable element below.

Plant procedures establish limits and controls for harmful chemicals on corrosion resistant alloys. The Water Chemistry Control Program is primarily a mitigative program used to minimize contaminant concentration and mitigate aging effects such as loss of material, cracking, and loss of heat transfer.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

Water quality is verified by continuous monitoring or through sampling in accordance with the EPRI guidelines discussed previously.

This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 states that water quality (pH and conductivity) are maintained in accordance with the EPRI guidelines. EPRI TR-105714, Rev. 4 lists pH and conductivity as primary water diagnostic parameters to be monitored during power operation, but does not provide acceptance limits. NUREG-1801 lists lead as one of the secondary water chemistry parameters recommended for monitoring by EPRI TR-102134. PBNP does not routinely monitor for lead, nor is it required to be monitored by Revision 5 of the EPRI report. PBNP also deviates slightly from EPRI TR-102134, Rev. 5 in the manner in which the hydrazine concentration is maintained because PBNP only has the capability for batch hydrazine additions utilizing the Auxiliary Feedwater Pumps. EPRI TR-102134, Rev. 5 lists pH and conductivity as secondary water diagnostic parameters to be monitored when the RCS temperature is > than 200 degrees F, but does not provide acceptance criteria. These exceptions are justified since we use more current guidance provided in the later EPRI document revisions and due to system limitations.

Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

Detection of Aging Effects

The Water Chemistry Control Program mitigates aging effects such as loss of material due to general, pitting, and crevice corrosion, MIC, cracking due to SCC, and fouling buildup by controlling the chemical species that cause the underlying aging mechanisms that result in the aging effects. The chemistry parameters measured are defined and listed for all modes of operation. The Water Chemistry Control Program does not detect aging effects, however in selected areas it does monitor for iron and copper presence, which could indicate loss of material in some components. In addition, inspections of selected components at susceptible locations in low-flow or stagnant portions of a system performed under the One-Time Inspection Program provide verification of the effectiveness of the Water Chemistry Control Program.

Enhancements to the Water Chemistry Control Program include revisions to existing implementing procedures to include the applicable aging effects.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

Monitoring and trending requirements for all parameters controlled by the Water Chemistry Control Program are included in the associated implementing documents. Monitoring and trending are based on the EPRI guidelines and plant operating conditions. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling and monitoring is utilized to verify the effectiveness of these actions. This is normal operating procedure to verify that the corrective action has satisfactorily corrected the parameter that was out of the acceptable range.

Enhancements to the Water Chemistry Control Program include revising procedures to add a step or note to state that additional sampling is performed after corrective actions have been taken, whenever there is no continuous monitoring of a parameter which was found to be outside the specified values. This is to verify that the corrective actions have returned the parameter to within the specified values.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

The acceptance criteria for the chemistry parameters required to be monitored and controlled are based on the EPRI guidelines, PBNP Technical Specifications and the Technical Requirements Manual. As discussed above, some of the parameters monitored are used for diagnostic purposes only and do not have acceptance criteria established by the EPRI guidelines. Water chemistry acceptance criteria is listed in the plant procedures.

Any evidence of unacceptable water chemistry results is evaluated, the underlying cause identified, and the condition corrected. Plant procedures have very definite steps to be taken when parameters are out of acceptable range.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Water Chemistry Control Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

The Water Chemistry Control Program has been in effect since initial plant operation and has been effective at maintaining the desired system water chemistry and detecting abnormal conditions, which have been corrected in an expedient manner. A review of condition reports/action requests supports the above statement as most are related to abnormal chemistry results during operational transients such as startups where the abnormal condition is expected, but the corrective action program is used for documentation.

The EPRI guidelines for water chemistry are being used and the controlling procedures refer and adhere to the limits specified in them. Over time, this has proven to be an effective method of controlling concentrations of parameters such as sulfates, chlorides, fluorides, dissolved oxygen, lithium, sodium, iron, and copper that are detrimental to certain alloys in both the primary and secondary systems. Controlling these parameters mitigates aging effects in primary and secondary system components.

Each unit had an Action Level (AL) 3 secondary chemistry excursion as a result of Low Pressure Turbine Modifications. The Unit 1 excursion occurred in April 1995. The AL3 limits for Organic Adjusted Cation Conductivity exceeded the AL3 limit of 7 µmhos/cm on April 17, 1995 (peak of 19.5 µmhos/cm). This was attributed to increased sulfates and chlorides. The plant remained in AL3 for approximately 14 hours, during which time power never exceeded 30%. Sulfates and chlorides peaked at 155 ppb and 120 ppb respectively during the startup. The Unit 2 excursion occurred in February/March 1999. The AL3 limits for Organic Adjusted Cation Conductivity exceeded the AL3 limit of 7 µmhos/cm on March 4, 1999 (peak of 9.35 µmhos/cm). This was also attributed to increased sulfates and chlorides. The plant remained in AL3 for approximately 12 hours, during which time power never exceeded 30%. Sulfates and chlorides peaked at 742 ppb and 156 ppb respectively during the startup.

There is no recollection of any resin intrusion events into the primary system. A historical review of Reactor Coolant System data for sulfate as an indicator of a resin intrusion event did not reveal any evidence of such an event.

An assessment performed by Nuclear Oversight in 2003 concluded that the chemistry program meets expectations. A self assessment conducted in mid-2003 concluded that the primary and secondary water chemistry programs meet station requirements, however some process weaknesses exist. These process weaknesses are being tracked via the corrective action process. A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no other issues or findings that could impact the effectiveness of the Water Chemistry Control Program.

Review of plant-specific operating experience also indicates that the chemistry program is performing its function of mitigating aging effects. No reports were found that attributed water chemistry as the cause of component deterioration, showing signs of aging effects, or failing to perform its function. Action Requests are initiated when water chemistry is found to be out of specification, and most of the instances occur during start-up when parameters are quickly changing and it is more difficult to control water chemistry. The time duration of out of specification water chemistry is minimal and there is no evidence of having caused detrimental effects on system components. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Water Chemistry Control Program provides reasonable assurance that aging effects will be adequately managed such that systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

The Water Chemistry Control Program has been an ongoing program at PBNP since initial operation and has been improved over the years to reflect lessons learned in the industry. The program incorporates the recommended practices of the Electric Power Research Institute and the Institute of Nuclear Power Operation.

The Water Chemistry Control Program provides reasonable assurance that the water environment to which piping and associated components are exposed will minimize corrosion. This is accomplished through effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. Furthermore, the chemistry analyses are governed by the plant Analytical Quality Assurance Program to assure accurate results. Chemistry data is also monitored for trends that might be indicative of an underlying operational problem. This will provide for early detection of any conditions which might adversely affect component intended functions.

The overall effectiveness of the Water Chemistry Control Program is supported by the excellent operating experience for systems and components which are influenced by the Water Chemistry Control Program. No chemistry related degradation has resulted in loss of component intended functions on any systems for which the water chemistry is actively controlled.

B3.0 TLAA SUPPORT ACTIVITIES

B3.1 Environmental Qualification Program

Program Description

The EQ Program 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. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered TLAA for license renewal. The EQ Program ensures that these EQ components are maintained within the bounds of their qualification bases.

NUREG-1801 Consistency

The EQ Program is an existing program, as currently established to meet PBNP commitments for 10 CFR 50.49, that is consistent with NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Section X.E1, "Environmental Qualification of Electric Components" (Reference 3).

Exceptions to NUREG-1801

None

Enhancements

Enhancements to the EQ Program include completing the EQ Backlog Elimination Project to eliminate the backlog of outstanding EQ related tasks and addressing the recommendations from an independent assessment of the program, which include field verification of EQ components and the completion of EQ Checklist reviews. These enhancements are intended to improve the overall health and effectiveness of the EQ Program. Although these enhancements are needed to satisfy the NUREG-1801 aging management program, they are already required by existing PBNP commitments to 10 CFR 50.49 and do not indicate requirements that are unique to license renewal. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the EQ Program, are described below. The results of an evaluation of each key element against NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Section X.E1, "Environmental Qualification of Electric Components," is also provided below.

Scope of Program

The EQ Program includes certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

10 CFR 50.49 does not require actions that prevent aging effects. EQ Program actions that could be viewed as preventive actions include (a) establishing the component service condition tolerance and aging limits (e.g., qualified life or condition limit), and (b) where applicable, requiring specific installation, inspection, monitoring or periodic maintenance actions to maintain component aging effects within the bounds of the qualification bases.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The qualified life of a component in the EQ Program is not based on condition or performance monitoring. However, pursuant to Regulatory Guide 1.89, such monitoring programs are an acceptable basis to modify a qualified life through reanalysis. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that a component is within the bounds of its qualification bases, or as a means to modify the qualified life.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

10 CFR 50.49 does not require the detection of aging effects for inservice components. As implemented by the EQ Program, 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 bases, or as a means to modify the qualified life.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of inservice components to manage the effects of aging. EQ Program actions that could be viewed as monitoring include monitoring how long qualified components have been installed. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that a component is within the bounds of its qualification bases, or as a means to modify the qualified life.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

10 CFR 50.49 acceptance criteria, as implemented in the EQ Program, are that an inservice EQ component is maintained within the bounds of its qualification bases, including (a) its established qualified life, and (b) continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device. When monitoring is used to modify a component qualified life, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

If a component in the EQ Program is found outside the bounds of its qualification basis, corrective actions are implemented in accordance with the corrective action program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the 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. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The EQ Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

The EQ Program is implemented through the use of plant policies, directives, and procedures. The EQ Program will continue to comply with 10 CFR 50.49 throughout the renewal period, including development and maintenance of qualification documentation demonstrating reasonable assurance that a component can perform required functions during harsh accident conditions. EQ Program documents identify the applicable environmental conditions for the component locations. EQ Program qualification files are maintained at PBNP in an auditable form for the duration of the installed life of the component. EQ Program documentation is controlled under the PBNP QA program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

The EQ Program includes consideration of operating experience to modify the qualification bases and conclusions, including qualified life. Compliance with 10 CFR 50.49 provides reasonable assurance that components can perform their intended function(s) during accident conditions after experiencing the effects of inservice aging. Although program execution issues have been experienced at

PBNP, a review of plant-specific and industry operating experience identified no premature failures due to aging effects that could affect the qualified life of an EQ component.

NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 were reviewed to determine the effectiveness of the EQ Program as it currently exists.

Numerous weaknesses were identified from a design and programmatic perspective. These weaknesses are indicative of issues related to executing existing PBNP commitments to 10 CFR 50.49 and do not indicate that changes are needed to the requirements (i.e., scope, qualification methods, acceptance criteria, etc.) established by these commitments. The EQ Program, as currently committed to 10 CFR 50.49, provides reasonable assurance that the intended functions of EQ components will be maintained through the period of extended operation.

An EQ Program Backlog Elimination Project has been undertaken to eliminate the backlog of outstanding EQ related tasks, in order to improve the overall health and effectiveness of the EQ Program. Policies and procedures that govern the EQ Program have already been revised to strengthen the administrative controls associated with the program. Work is ongoing to eliminate the backlog of outstanding EQ related tasks.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The EQ Program has been demonstrated to be capable of programmatically managing the qualified lives of the components falling within the scope of the program for license renewal. Based upon a review of the existing program and operating experience, the effective implementation of the EQ Program will provide reasonable assurance that (a) the aging effects will be managed, and (b) EQ components will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation. Therefore, the EQ Program will be an acceptable aging management program for license renewal under 10 CFR 54.21(c)(1)(iii) during the period of extended operation.

B3.2 Fatigue Monitoring Program

Program Description

The Fatigue Monitoring Program is a confirmatory program that monitors loading cycles due to thermal and pressure transients and cumulative fatigue usage for selected reactor coolant system and other component locations. The program provides an analytical basis for confirming that the actual number of cycles does not exceed the number of cycles used in the design analysis, and the cumulative fatigue usage will be maintained below the allowable limit during the period of extended operation.

The impact of the effects of reactor coolant environment on component fatigue life has been evaluated for a sample of critical components, including the seven component locations selected in NUREG/CR-6260. Appropriate environmental fatigue factors were calculated using the formulae from NUREG/CR-6583 for carbon and low-alloy steels and NUREG/CR-5704 for austenitic stainless steels. These critical component locations were determined to be acceptable for the period of extended operation, including the effects of reactor coolant environment. The acceptability of these critical component locations, including the effects of reactor coolant environment, will continue to be confirmed by the Fatigue Monitoring Program.

NUREG-1801 Consistency

The Fatigue Monitoring Program is an existing program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section X.M1, “Metal Fatigue of Reactor Coolant Pressure Boundary” (Reference 3).

Exceptions to NUREG-1801

None

Enhancements

Enhancements to the Fatigue Monitoring Program include modifying existing plant documents to monitor loading cycles and fatigue usage, including the effects of reactor water environment. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Fatigue Monitoring Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section X.M1, “Metal Fatigue of Reactor Coolant Pressure Boundary,” is also provided below.

Scope of Program

The scope of the Fatigue Monitoring Program includes ASME Class 1 and selected Class 2 components analyzed to Class 1 rules (i.e., main feedwater nozzles) for which a cyclic or fatigue design basis exists.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

The Fatigue Monitoring Program includes preventive measures to mitigate fatigue cracking of metal components of the reactor coolant pressure boundary and the Unit 1 and 2 main feedwater nozzles, and will provide adequate margin against fatigue cracking of these components due to anticipated cyclic strains.

Tracking of operating transient cycles and maintaining the fatigue usage factor below the design code limit of 1.0, including the effects of reactor water environment, will provide adequate margin to prevent fatigue cracking of reactor coolant system components and the Unit 1 and 2 main feedwater nozzles due to anticipated cyclic strains.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The Fatigue Monitoring Program monitors plant pressure and temperature transients that cause cyclic strains and are significant contributors to fatigue damage or crack growth. The Fatigue Monitoring Program consists of automated cycle counting to count the number of plant transients that cause significant fatigue damage. Fatigue usage factors are tracked for bounding component locations of the reactor coolant pressure boundary and the Unit 1 and 2 main feedwater nozzles.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

The Fatigue Monitoring Program provides for periodic updates of the plant cycle count and fatigue usage calculations. The metal fatigue aging effects are planned to be monitored using FatiguePro, which is an EPRI software product for plant transient monitoring and fatigue usage calculations. Plant operating cycles will be tracked against design limits. Fatigue usage factors will be computed on an on-going basis for bounding components using plant instrument data.

Enhancements to the Fatigue Monitoring Program include modifying existing plant documents to monitor loading cycles and fatigue usage, including the effects of reactor water environment.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

The Fatigue Monitoring Program includes monitoring the number and severity of plant design transients and an on-going fatigue analysis of a sampling of component locations whose level of metal fatigue is expected to be most adversely affected by the combined effects of plant cycles and reactor water environment. The monitored population includes each of the component locations identified in NUREG/CR-6260 for older vintage Westinghouse plants as well as others.

The Fatigue Monitoring Program will ensure that the extent of the fatigue aging effect is quantifiable on an on-going basis and that alternative or mitigative actions can be taken before there is a loss of any component's intended function.

The program monitors operating transients to-date, calculates fatigue usage factors to-date, and allows corrective measures to be implemented ahead of time to ensure that structural margins required by the codes used in the original plant design are maintained through the extended period of operation. The operating cycle recording and assessment frequency ensures that normal operating transients that might occur during the plant operational period will not compromise these limits. The evaluation locations have been chosen to ensure that locations that might approach acceptance limits will be monitored. The program also includes provisions to identify deviations from expected usage factor accumulation so that appropriate corrective actions can be taken before structural margins are degraded to unacceptable levels.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

The acceptance criteria consists of maintaining the fatigue usage factor less than or equal to the design code allowable limit of 1.0, considering environmental fatigue effects, and cumulative number of plant cycles less than or equal to the cyclic design basis. For the components for which an environmentally-assisted fatigue evaluation was performed, the fatigue usage factor limit will be taken to be a value of ($1/F_{en}$). The acceptance criteria will ensure that all original structural margins considered in the plant design are maintained through the extended period of operation.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as committed in Section 1.4 of the PBNP FSAR.

The Fatigue Monitoring Program provides for corrective actions to prevent the fatigue usage factor from exceeding the design code limit of 1.0, including the effects of reactor coolant environment, or the cumulative number of plant cycles from exceeding the cyclic design basis during the period of extended operation. The Fatigue Monitoring Program uses FatiguePro to perform an analysis of each monitored component location using actual plant data, and to provide the basis for proactive action to maintain the cyclic design basis and the fatigue usage factors below code limits. Corrective actions include a review of additional affected component locations.

For component locations for which it can not be demonstrated that the cyclic design basis can be maintained or the fatigue usage factor remains below the design code limit of 1.0, including the effects of reactor coolant environment, during the period of extended operation corrective actions can include a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded, repair or replacement of the component, or managing the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Fatigue Monitoring Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

The Fatigue Monitoring Program includes reviews of both industry and plant-specific operating experience regarding fatigue cracking for applicability to PBNP-1 and 2. These on-going reviews will be considered when selecting additional monitored components.

Several industry issues have arisen which have provided knowledge about the propensity for fatigue cracking in Class 1 and 2 components. Starting in 1979, several PWRs experienced main feedwater piping and nozzle fatigue cracking resulting from thermal stratification cycling during low flow and hot standby conditions. NRC Bulletin 79-13 dealt with fatigue cracking of steam generator feedwater nozzles (Class 2 component). As reported in 1979 (Reference 26), PBNP Unit 2 experienced shallow (0.047 inch maximum) cracking in the area of the auxiliary feedwater connection to the main feedwater piping. Visual examination revealed similar cracking in Unit 1. The design of the currently installed replacement steam generators for Unit 1 retain the propensity for both slug feeding and thermal stratification effects. Thus, the Unit 1 main feedwater nozzles are monitored for slug feeding and thermal stratification cycling loadings. The currently installed replacement steam generators for PBNP Unit 2 include main feedwater nozzle features that preclude thermal stratification cycling effects, but are affected by slug feeding loadings. The Unit 2 main feedwater nozzles are monitored for slug feeding effects.

NRC Bulletin 88-08 addressed the potential for fatigue cracking in normally stagnant piping systems attached to the reactor coolant system. Cold leg safety injection lines at Westinghouse plants have experienced a number of these pipe cracking incidents (Farley-Unit 2 in 1987 and Sequoyah Unit 2 in 1996) (References 29 and 27) and thermal sleeve cracking (Trojan and McGuire Unit 1) (Reference 28). These piping and nozzles were associated with the 10-inch accumulator line connection to the cold legs. The Fatigue Monitoring Program includes these nozzles as monitored component locations. These locations are identical to the NUREG/CR-6260 location.

NRC Bulletin 88-11 addressed thermal fatigue cracking of pressurizer surge piping. Various pressurizer surge line welds at PBNP Units 1 and 2 have been examined in the past, with no reportable indications having been found. For example, the Unit 1 surge line reducer-to-pipe weld has been examined, as well as two other generally high fatigue usage locations (i.e., safe end weld and the hot leg tee weld) in the surge lines for both units. The Fatigue Monitoring Program includes the pressurizer surge line nozzle, the RCS hot leg surge line nozzle and the pressurizer surge line reducer weld as monitored components.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Fatigue Monitoring Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Fatigue Monitoring Program has been demonstrated to be effective in managing low-cycle fatigue effects and capable of programmatically managing the cyclic life of those components falling within the scope of the program for license renewal. Based upon a review of the existing program and operating experience, the Fatigue Monitoring Program provides reasonable assurance that the aging effects will be managed and the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B3.3 Pre-Stressed Concrete Containment Tendon Surveillance Program

Program Description

The Pre-Stressed Concrete Containment Tendon Surveillance Program is a confirmatory program that monitors the loss of containment prestressing forces in containment tendons throughout the life of the plant, including the period of extended operation. This program consists of an assessment of the results of the tendon prestressing force measurements performed in accordance with ASME Section XI, Subsection IWL. The assessment related to the adequacy of the prestressing forces will consist of the establishment of (a) acceptance criteria, and (b) trend lines. The acceptance criteria will normally consist of a predicted lower limit (PLL) and the minimum required prestressing force or value (MRV). The trend line represents the trend of prestressing forces based on actual measured forces. Maintaining the prestressing force trend lines above the PLL ensures that the prestressing forces in the containment would not be below the MRVs prior to the end of the period of extended operation. In accordance with the requirements of 10 CFR 50.55a(b)(2)(viii)(B), an evaluation will be performed if the trend lines predict the prestressing forces in the containment to be below the MRV before the next scheduled inspection.

The PLL and upper bound of the tolerance band for each tendon group was recalculated for the 60 year life of the tendons based on the Actual Seating Stress vs. the Minimum Design Seating Stress. The Calculation was performed using the guidelines provided in NRC Regulatory Guide 1.35.1 (Reference 30). NRC Information Notice 99-10 (Reference 31) discusses the potential for tendon wire breakage, the effects of high temperature on tendon prestress force, and makes recommendations regarding the trending of prestress forces. The new calculation takes wire breakage into account and used a 1% broken/missing wire allowance. The results of the calculation indicate that the PLL remains above the MRV through the life of the plant, including the period of extended operation.

During the scheduled surveillances, the tendon prestress force is measured for a random sample of each tendon group. One tendon in each group is designated as the common tendon. The prestress force in the common tendon is measured during each surveillance and is used to establish the trend of prestress loss for the group. An evaluation is required if the acceptance criteria of ASME Section XI, Subsection IWL is not met, or if the trend indicates that tendon force(s) would be less than the MRV before the next scheduled inspection, as required by 10 CFR 50.55a(b)(2)(viii)(B).

NUREG-1801 Consistency

The Pre-Stressed Concrete Containment Tendon Surveillance Program is an existing program that is consistent with NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section X.S1, “Concrete Containment Tendon Prestress” (Reference 3).

Exceptions to NUREG-1801

None

Enhancements

Enhancements to the Pre-Stressed Concrete Containment Tendon Surveillance Program include more detailed requirements regarding the trending and evaluation of inspection results. Additionally, the IWL implementation schedule will be revised to include the period of extended operation. These enhancements are required to satisfy the NUREG-1801 aging management program requirements. Details of the enhancements are included in the appropriate element descriptions below.

Enhancements are scheduled for completion prior to the period of extended operation.

Aging Management Program Elements

The key elements, which are used in the Pre-stressed Concrete Containment Tendon Surveillance Program, are described below. The results of an evaluation of each key element against NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Section X.S1, “Concrete Containment Tendon Prestress,” is also provided below.

Scope of Program

The program addresses the assessment of Unit 1 and Unit 2 containment tendon wire prestressing forces. During the scheduled surveillances, the tendon prestress force is measured for a random sample of each tendon group. One tendon in each group is designated as the common tendon. The prestress force in the common tendon is measured during each surveillance and is used to establish the trend of prestress loss for the group. The trend of prestress force for each group is compared to the MRV to ensure that the prestress force will not fall below the MRV prior to the next scheduled inspection. PBNP calculations indicate that the PLL remains above the MRV throughout the life of the plant, including the period of extended operation.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Preventive Actions

There are no preventive actions associated with this program. As long as the tendon wire prestressing values are found to be within the acceptance criteria no actions are required. Maintaining the prestress above the MRV will ensure that the structural and functional adequacy of the containment are maintained.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Parameters Monitored or Inspected

The parameters monitored are the containment tendon wire prestressing forces in accordance with the requirements specified in Subsection IWL of Section XI of the ASME Code, which is described in the PBNP ISI IWL Containment Inspection Program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Detection of Aging Effects

The loss of tendon wire prestressing forces is detected by performance of the tendon inspections conducted per the PBNP ISI IWL Containment Inspection Program.

Enhancements to the Pre-Stressed Concrete Containment Tendon Surveillance Program will result in the inclusion of more detailed requirements regarding the trending and evaluation of inspection results. Additionally, the IWL implementation schedule will be revised to include the period of extended operation.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Monitoring and Trending

The tendon wire prestressing forces are compared to the PLL and upper bound lines that were developed for the period of extended operation. Prestress force trends are also evaluated to ensure that the prestress force will not fall below the MRV prior to the next scheduled inspection.

New common tendons which have not been previously retensioned were selected for the 28th year surveillance. These tendons will be tested in future surveillances in order to establish valid prestress force trend lines.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Acceptance Criteria

An evaluation is required if the acceptance criteria of ASME Section XI, Subsection IWL is not met, or if the trend indicates that tendon force(s) would be less than the MRV before the next scheduled inspection, as required by 10 CFR 50.55a(b)(2)(viii)(B).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed in Section 1.4 of the PBNP Final Safety Analysis Report (FSAR).

This element is consistent with the corresponding NUREG-1801 aging management program element.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Administrative Controls

The Pre-Stressed Concrete Containment Tendon Surveillance Program is implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B and ANSI N18.7-1976, as committed in Section 1.4 of the PBNP FSAR.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Operating Experience

The calculated PLL and past inspection results indicate that the containment tendon wire prestress forces for PBNP Units 1 & 2 are expected to remain above the MRV for the period of extended operation.

During the preparations for the 28th year tendon surveillance, it was discovered that the designated “common” or “control” tendons (i.e., those tendons in each group that are tested every surveillance in order to establish the trend of prestress force for that group) had been retensioned during each preceding surveillance as recommended by earlier versions of Reg. Guide 1.35. Periodic retensioning of these tendons did not allow an accurate determination of the prestress force relaxation trends. New common tendons which have not been previously retensioned were selected for the 28th year surveillance. These tendons will be tested in future surveillances in order to establish valid prestress force trends.   The NRC was advised of this situation in a June, 1999 letter. (Reference 11).

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Pre-Stressed Concrete Containment Tendon Surveillance Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

This element is consistent with the corresponding NUREG-1801 aging management program element.

Conclusion

The Pre-Stressed Concrete Containment Tendon Surveillance Program provides reasonable assurance that the aging effect of loss of containment prestressing forces will be managed, such that the containment tendons will continue to perform their intended function consistent with the current licensing basis during the extended period of operation. The containment tendons have been inspected eight times on each unit since the plant began operation. The tendon prestress PLL has been recalculated and plotted using the actual seating stress instead of the design stress. The recalculation accounted for a 1% allowance for wire breakage and considered a 60 year life of the plant. The measured prestress force of the designated common tendons will be trended and compared to the PLL and MRV.

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APPENDIX C

(Not Used for This Application)

APPENDIX C
Contents

C1.0 APPENDIX C - NOT USED

Appendix C is not used in this application.

APPENDIX D

TECHNICAL SPECIFICATION CHANGES

APPENDIX D
Contents

D1.0 APPENDIX D - TECHNICAL SPECIFICATIONS CHANGES

10 CFR 54.22 requires that an application for license renewal include any Technical Specification changes or additions that are necessary to manage the effects of aging during the period of extended operation. A review of the information provided in this License Renewal Application and the Point Beach Technical Specifications confirms that no changes to the Technical Specifications are necessary.

APPENDIX E

(Provided as Linked Document)

APPENDIX E
Contents

E1.0 APPENDIX E - ENVIRONMENTAL REPORT

This page provides a link to the Environmental Report.