1.1 GENERAL INFORMATION – 10 CFR 54.19

1.1.1 NAMES OF APPLICANT AND CO-OWNERS

Southern Nuclear Operating Company hereby applies for renewed operating licenses for Plant Hatch Units 1 and 2. SNC submits this application individually and as agent for the co-owner licensees named on the operating license. The co-owner licensees are:

- Georgia Power Company
- Oglethorpe Power Corporation
- Municipal Electric Authority of Georgia
- City of Dalton, Georgia

1.1.2 ADDRESSES OF APPLICANT AND CO-OWNERS

Southern Nuclear Operating Company, Inc.
40 Inverness Center Parkway
P.O. Box 1295
Birmingham, Alabama 35201-1295

Georgia Power Company
241 Ralph McGill Boulevard
Atlanta, Georgia 30308

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

Municipal Electric Authority of Georgia
1470 Riveredge Parkway
Atlanta, Georgia 30328

The City of Dalton
1200 V. D. Parrott, Jr. Parkway
Dalton, Georgia 30720

1.1.3 DESCRIPTIONS OF BUSINESS OR OCCUPATION OF APPLICANT AND CO-OWNERS

Southern Nuclear Operating Company, Inc.

SNC is engaged in the operation of nuclear power plants. SNC operates the Edwin I. Hatch Nuclear Plant (HNP), Units 1 and 2 and the Vogtle Electric Generating Plant (VEGP), Units 1 and 2 for Georgia Power Company (GPC), Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia (the co-owners); and the Joseph M. Farley Nuclear Plant (FNP) for Alabama Power Company. The combined electric generation of the three plants is in excess of 5,900 MW.

SNC is the exclusive licensed operator of the co-owners' nuclear facility, HNP, which is the subject of this application. The current Unit 1 license (Facility Operating License No. DPR-57) expires on August 6, 2014, and the current Unit 2 license (Facility Operating License No. NPF-5) expires on June 13, 2018. SNC will be named as the exclusive licensed operator on the renewed operating licenses.

Georgia Power Company

Georgia Power Company (GPC) is engaged in the generation and transmission of electricity and the distribution and sale of such electricity within the State of Georgia. Georgia Power Company serves more than 1.7 million customers in a service area of approximately 57,000 square miles constituting 97 percent of the State of Georgia's land area. With a rated capability of approximately 14,000 MW, GPC currently provides retail electric service in all but 6 of Georgia's 159 counties. GPC is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed licenses.

Oglethorpe Power Corporation

Oglethorpe Power Corporation (an Electric Membership Corporation) supplies electricity at wholesale to 39 Electric Membership Corporations in the State of Georgia, which in turn distribute this electricity at retail to their residential, commercial and industrial customers. Oglethorpe is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed licenses.

Municipal Electric Authority of Georgia

MEAG is an electric generation and transmission public corporation, which provides wholesale power to 48 communities in the State of Georgia and other wholesale customers. These communities, in turn, supply electricity to more than 675,000 retail consumers, in their respective service areas across the state, representing approximately 10 percent of Georgia’s population. MEAG is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed license.

City of Dalton

The City of Dalton is a municipality within the State of Georgia. Acting by and through Dalton Utilities, its Board of Water, Light and Sinking Fund Commissioners, Dalton owns electric generation capacity, transmission capacity and a distribution system. Dalton is a duly incorporated municipality under the laws of the State of Georgia. Dalton is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed licenses.

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

SOUTHERN NUCLEAR OPERATING COMPANY, INC.

SNC is a Delaware corporation with its principal office in Birmingham, Alabama. It is a wholly-owned subsidiary of Southern Company, a company registered under the Public Utility Holding Company Act of 1935, having its principal place of business in Atlanta, Georgia. Other subsidiaries of Southern Company include Georgia Power Company, Alabama Power

Company, Gulf Power Company, Mississippi Power Company, Savannah Electric, Southern Company Services, Inc., Southern Linc, and Southern Energy.

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

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

Directors

A. W. Dahlberg, III Chairman & Chief Executive Officer Southern Company	270 Peachtree Street Atlanta, Georgia 30303
H. A. Franklin President and Chief Operating Officer Southern Company	270 Peachtree Street Atlanta, Georgia 30303
D. M. Ratcliffe President & Chief Executive Officer Georgia Power Company	241 Ralph McGill Boulevard Atlanta, Georgia 30308
E. B. Harris President and Chief Executive Officer Alabama Power Company	600 North 18th Street Birmingham, Alabama 35202
W. G. Hairston, III President & Chief Executive Officer Southern Nuclear Operating Company, Inc.	P.O. Box 1295 Birmingham, Alabama 35201

Principal Officers

W. G. Hairston III, President and CEO, Birmingham, Alabama
J. D. Woodard, Executive Vice President, Birmingham, Alabama
D. N. Morey III, Farley Vice President, Birmingham, Alabama
H. L. Sumner, Jr., Hatch Vice President, Birmingham, Alabama
J. B. Beasley, Jr., Vogtle Vice President, Birmingham, Alabama
L. B. Long, Technical Services Vice President, Birmingham, Alabama
J. W. Averett, Administrative Services Vice President, Birmingham, Alabama
J. O. Meier, Vice President and Corporate Counsel, Birmingham, Alabama
S. A. Mitchell, Corporate Secretary, Birmingham, Alabama
K. S. King, Comptroller and Treasurer, Birmingham, Alabama
D. J. Burnett, Assistant Corporate Secretary, Birmingham, Alabama

GEORGIA POWER COMPANY

GPC is a Georgia corporation with its principal office in Atlanta, Georgia. GPC is a wholly-owned subsidiary of Southern Company, a Delaware corporation with its principal office in Atlanta, Georgia.

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

Directors

Daniel P. Amos	1931 Wynnton Road Columbus, Georgia 31999
Juanita P. Baranco	7060 Jonesboro Road Morrow, Georgia 30260
William A. Fickling, Jr.	577 Mulberry Street, Suite 1100 Macon, Georgia 31202-1976
H. Allen Franklin	270 Peachtree Street, Suite 2200 Atlanta, Georgia 30303
L. G. Hardman, III	1731 North Elm Street Commerce, Georgia 30529
Warren Y. Jobe	270 Peachtree Street Atlanta, Georgia 30303
James R. Leintz, Jr.	600 Peachtree Street NE Atlanta, Georgia 30302-4899
Zell Miller	3455 Peachtree Road NE, Suite 750 Atlanta, Georgia 30326

G. Joseph Prendergrast	191 Peachtree Street, NE 31st floor Atlanta, Georgia 30308
David M. Ratcliffe	241 Ralph McGill Blvd., NE Atlanta, Georgia 30308
Herman J. Russell	504 Fair Street, SW Atlanta, Georgia 30313
William Jerry Vereen	301 Riverside Drive Moultrie, Georgia 31776-0460
Carl Ware	1 Coca Cola Plaza Atlanta, Georgia 30313

Principal Officers

David M. Ratcliffe, President and CEO, Atlanta, Georgia
T. A. Fanning, Executive V.P., Treasurer and CFO, Atlanta, Georgia
W. C. Archer, III, Executive V.P., External Affairs, Atlanta, Georgia
G. R. Hodges, Executive V.P., Customer Operations, Atlanta, Georgia
W. Y. Jobe, Executive V.P., Georgia Power Company, Atlanta, Georgia
L. J. Haynes, Sr. V.P., Marketing, Atlanta, Georgia
W. T. Dalke, Sr. V.P., Power Delivery, Atlanta, Georgia
J. K. Davis, Sr. V.P., Corporate Relations, Atlanta, Georgia
R. H. Haubein, Jr., Sr. V.P., GPC-Southern Company, Generation, Atlanta, Georgia
F. D. Williams, Sr. V.P., Resource Planning and Policy, Atlanta, Georgia

Neither GPC nor its corporate parent, Southern Company, is owned, controlled, or dominated by an alien, foreign corporation, or foreign government.

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

MEAG is public corporation and an instrumentality of the State of Georgia, a body corporate and politic, created by the General Assembly of the State of Georgia in its 1975 Session (Official Code of Georgia Annotated, Title 46, Chapter 3, Article 3).

The names and addresses of MEAG's principal officers and the members of its governing body, all of whom are citizens of the United States, are as follows:

Authority Members (Governing board)

John H. Flythe, Chairman of the Board	P. O. Box 631 Adel, Georgia 31620
Kelly Cornwell, Vice Chairman	P. O. Box 248 Calhoun, Georgia 30703-0248
Steve Rentfrow Secretary Treasurer	P. O. Box 1218 Cordele, Georgia 31010

Patrick Bowie, Board Member	P. O. Box 430 LaGrange, Georgia 30241
The Honorable Ansley L. Meaders, Board Member	205 Lawrence Street Marietta, Georgia 30061
Roland C. Stubbs Jr., Board Member	113 Sylvan Terrace Sylvania, Georgia 30467
The Honorable Gerald Thompson Board Member	P. O. Box 425 Fitzgerald, Georgia 31750
Kerry Waldron, Board Member	P. O. Box 672 Thomaston, Georgia 30286-0009
Joel T. Wood Board Member	P. O. Box 487 West Point, Georgia 31833

Principal Officers

Robert P. Johnston, President	14370 Riveredge Pkwy. NW Atlanta, Georgia 30328
Mary Jackson, Vice President and Chief Financial Officer	14370 Riveredge Pkwy. NW Atlanta, Georgia 30328
James Fuller, Treasurer	14370 Riveredge Pkwy. NW Atlanta, Georgia 30328

MEAG is neither owned, controlled, nor dominated by an alien, foreign corporation, or foreign government.

OGLETHORPE POWER CORPORATION

Oglethorpe Power Corporation (an Electric Membership Corporation) operating on a not-for-profit basis, was organized under the Georgia Electric Membership Corporation Act (Official Code of Georgia Annotated, Title 46, Chapter 3, Article 4) and other applicable laws of the State of Georgia.

The names and addresses of Oglethorpe's principal officers and the members of its governing body, all of whom are citizens of the United States, are as follows:

Board of Directors

J. Calvin Earwood, Chairman	2100 East Exchange Place Tucker, GA 30085-1349
Benny W. Denham, Vice Chairman	2100 East Exchange Place Tucker, GA 30085-1349

Mac F. Oglesby, Treasurer	2100 East Exchange Place Tucker, GA 30085-1349
Larry N. Chadwick, NW Regional Director	2100 East Exchange Place Tucker, GA 30085-1349
Sammy Jenkins, SE Regional Director	2100 East Exchange Place Tucker, GA 30085-1349
Sam Rabun, Central Regional Director	2100 East Exchange Place Tucker, GA 30085-1349
Ashley C. Brown, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349
Newton A. Campbell, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349
Wm. Ronald Duffy, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349
John S. Ranson, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349

Principal Officers

Thomas A. Smith, President and Chief Executive Officer	2100 East Exchange Place Tucker, GA 30085-1349
Michael W. Price, Chief Operating Officer	2100 East Exchange Place Tucker, GA 30085-1349
W. Clayton Robbins, Senior Vice President, Finance and Administration	2100 East Exchange Place Tucker, GA 30085-1349
Clarence D. Mitchell, Senior Vice President, Operations and Projects	2100 East Exchange Place Tucker, GA 30085-1349
Betsy Higgins, Vice President, Assistant to the CEO	2100 East Exchange Place Tucker, GA 30085-1349
Dale R. Murphy, Vice President, Planning and Administration	2100 East Exchange Place Tucker, GA 30085-1349
Robert D. Steele, Vice President, External Affairs	2100 East Exchange Place Tucker, GA 30085-1349

Glenn Loomer Vice President, Contracts and Analysis	2100 East Exchange Place Tucker, GA 30085-1349
Willie Collins, Controller and Chief Risk Officer	2100 East Exchange Place Tucker, GA 30085-1349
James E. Kofron, Corporate Treasurer	2100 East Exchange Place Tucker, GA 30085-1349
Patricia N. Nash, Corporate Secretary	2100 East Exchange Place Tucker, GA 30085-1349

Oglethorpe is neither owned, controlled, nor dominated by an alien, foreign corporation, or foreign government.

CITY OF DALTON

The names and addresses of Dalton's governing body (councilmen) and principal officers (mayor and city administrator), all of whom are citizens of the United States, are as follows:

Councilmen

Ray Elrod, Mayor	1508 Rio Vista Drive Dalton, GA 30720
Bobby Joe Grant	Paramount Printing P. O. Box 4569 Dalton, GA 30719-4569
Charles Whitener	123 Lisa Lane Dalton, GA 30720
Terry Christie	607 Murray Hill Drive Dalton, GA 30720
Michael Robinson	2006 West Brookhaven Circle Dalton, GA 30720

Officers

Ray Elrod, Mayor	1508 Rio Vista Drive Dalton, GA 30720

Butch Sanders, City Administrator	City Hall P. O. Box 1205 Dalton, GA 30722-1205
Faye Martin, City Clerk	City Hall P. O. Box 1205 Dalton, GA 30722-1205

Dalton is neither owned, controlled, nor dominated by an alien, foreign corporation, or foreign government.

The names and addresses of Dalton Utilities' governing body (Commissioners) and principal officers (chairman, president/chief executive officer, and secretary), all of whom are citizens of the United States, are as follows:

Commissioners

Justin Robinson Chairman	2203 Druid Lane Dalton, GA 30720
Norman D. Burkett Vice Chairman	2209 Rocky Face Circle Dalton, GA 30720
Todd Reigel Secretary	c/o Paradigm Printing, Inc. 429 Virgil Drive Dalton, GA 30720
George Mitchell	c/o Dalton Paving & Construction Company 530 North Elm Street Dalton, GA 30720
Jim Bethel	c/o J & J Industries, Inc. 818 J & J Drive Dalton, GA 30720

Officers

Justin Robinson Chairman	2203 Druid Lane Dalton, GA 30720
Don Cope President/Chief Executive Officer	1200 V. D. Parrott, Jr. Parkway Dalton, GA 30720

Todd Reigel
Secretary

c/o Paradigm Printing, Inc.
429 Virgil Drive
Dalton, GA 30720

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

SNC requests a Class 104 operating license for Plant Hatch Unit 1 and a Class 103 operating license for Unit 2 (License Nos. DPR-57 and NPF-5, respectively) for a period 20 years beyond the expiration of the current licenses, midnight, August 6, 2014 for Unit 1 and midnight, June 13, 2018 for Unit 2.

Because the current licensing basis is carried forward with the possible exception of some aging issues, Southern Nuclear expects the form and content of the licenses to be generally the same as they now exist. Southern Nuclear, thus, also requires similar extensions of specific licenses under Parts 30, 40, and 70 that are contained in the current operating licenses.

1.1.6 EARLIEST AND LATEST DATES FOR ALTERATIONS, IF PROPOSED

No physical plant alterations or modifications have been identified as necessary in order to implement the provisions of this application.

1.1.7 RESTRICTED DATA

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

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

1.1.8 REGULATORY AGENCIES

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

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

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

1.1.9 LOCAL NEWS PUBLICATIONS

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

The Baxley News-Banner
P.O. Box 409
Baxley, Georgia 31513
912-367-2468
Fax-912-367-0277

Vidalia Advance-Progress
P.O. Box 669
Vidalia, GA 30474
912-537-4899
Fax-912-537-4899

The Tattnall Journal
P.O. Box 278
Reidsville, GA 30453
912-557-6761
Fax-912-557-4132

The Jeff Davis Ledger
P.O. Box 338
Hazlehurst, GA 31539
912-375-4225
Fax-912-375-3704

The Macon Telegraph
P.O. Box 4167
Macon, GA 31208
912-744-4200
Fax-912-744-4385

Savannah Morning News
P.O. Box 1088
Savannah, GA 31402
912-236-9511
Fax-912-234-6522

1.1.10 CONFORMING CHANGES TO STANDARD INDEMNITY AGREEMENT

10 CFR 54.19(b) requires that “each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.” Article VII of the original Indemnity Agreement, which was issued on August 2, 1973, along with the HNP Materials License, provides that the Agreement will terminate at the expiration of the license identified in Item 3 of the Attachment

(SNM-1378). Since August 2, 1973, the Indemnity Agreement has been amended from time to time. Two of these amendments added license numbers DPR-57 and NPF-5 to Item 3 of the Attachment. As a consequence of these amendments, the existing Indemnity Agreement is presently due to terminate at midnight, June 13, 2018, as the last of these two licenses expires. SNC requests that conforming changes be made to Item 3 of the Attachment to the Indemnity Agreement (and any other provision of the Attachment or Indemnity Agreement) to make clear that the Indemnity Agreement is extended until the expiration date of the renewed HNP operating licenses issued by the Commission in response to this application.

1.2 GENERAL LICENSE INFORMATION

1.2.1 APPLICATION UPDATES, RENEWED LICENSES, AND RENEWAL TERM OPERATION

In accordance with 10 CFR 54.21(b), during NRC review of this application, SNC will provide an annual update to the application to reflect any information updates and agreements made with the NRC. SNC plans to work with the NRC to establish an application update procedure that is most beneficial toward supporting NRC's review process, rather than associating this requirement with a specific date based on the application submittal date.

In accordance with 10 CFR 54.37(b), SNC will maintain a summary list of programs in the FSAR which are required to manage the effects of aging and the evaluation of time-limited aging analyses for the systems, structures or components in the scope of license renewal during the period of extended operation.

1.2.2 INCORPORATION BY REFERENCE

The only documents to be incorporated by reference as part of this application are those documents specifically identified in sections titled “Documents Incorporated by Reference.” Any document references, either in text or in sections titled “General References” are listed for information only.

1.2.3 CONTACT INFORMATION

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

Mr. H. L. Sumner
Vice President - Hatch Project
Southern Nuclear Operating Company
40 Inverness Center Parkway
P.O. Box 1295
Birmingham, AL 35201-1295

with copies to:

Mr. Stan Blanton
Balch and Bingham
P.O. Box 306
Birmingham, AL 35201

Mr. C. R. Pierce
Southern Nuclear Operating Company
40 Inverness Center Parkway
P. O. Box 1295
Birmingham, AL 35201-1295

1.3 PURPOSE

This document is intended to provide information required by 10 CFR to support the application for a renewed license for the Edwin I. Hatch Nuclear Plant. The application contains technical information required by 10 CFR 54.21, technical specification changes required by 10 CFR 54.22, and environmental information required by 10 CFR 54.23. The information contained herein is intended to provide the NRC with an adequate basis to make the finding required by 10 CFR 54.29.

1.4 DESCRIPTION OF EDWIN I. HATCH NUCLEAR PLANT

Plant Edwin I. Hatch is a two-unit boiling water reactor (BWR) located on the south side of the Altamaha River in Appling County, Georgia, approximately 11 miles north of Baxley, Georgia. The reactor buildings and turbine buildings are separate for each unit. The control building is a shared facility between the two turbine buildings. The turbine buildings and control building are connected in such a manner as to provide a common turbine hall. Similarly, the refueling floors of both reactor buildings are joined together into a single area. The nuclear steam supply systems (NSSS) for both units include BWR 4, 1967 product line, 218-in. vessels, designed and supplied by GE. The containments are of the Mark I design, incorporating a drywell and torus to provide pressure suppression. The design operating power level for both units is 2763 MWt.

1.5 APPLICATION STRUCTURE

The application is divided into the following major sections:

***Section 1** – Introduction and Administrative Information*

This section describes the plant and states the purpose for this application. Included in this section are the names, addresses, business descriptions, and organization and management descriptions of the applicant and the co-owners of Plant Hatch, as well as other administrative information.

***Section 2** – Structures and Components Subject To An Aging Management Review*

A scoping and screening methodology is presented in this section. This section satisfies the requirements of 10 CFR 54.21(a)(2) to describe and justify the methods used to identify those structures and components subject to an aging management review (AMR).

Also included in this section are the scoping and screening results. The scoping results are presented in Table 2.2-1. This table lists plant system functions and denotes which functions are within license renewal scope.

Screening results are presented in sections 2.3 through 2.5. The screening results consist of lists of component types that require an aging management review, arranged by system. Also included with the screening results, as background information, are brief descriptions of in-scope system functions (intended functions) and associated systems.

Key intended function evaluation boundary drawings for most mechanical intended functions are provided as information under separate cover and do not constitute a part of this application.

***Section 3** – Aging Management Review Results*

AMR results are presented in tabular form, arranged by the system or structure principally associated with one or more intended functions. These tables identify the aging effects and the programs credited with managing the aging effects for component groups within the scope of license renewal.

***Section 4** – Time Limited Aging Analyses*

Time limited aging analyses (TLAAs) are discussed in this section, with a disposition method specified for each.

***Appendix A** – Final Safety Analysis Report Supplement*

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

Appendix B – Aging Management Programs and Activities

Program summaries are provided in Appendix A – FSAR Supplement.

Appendix C – Commodity Group Aging Management Review Results

Each structure or component subject to aging management review was evaluated in one or more AMRs. The AMR results are summarized in section C.2. A discussion of aging effect determinations is provided in section C.1.

Appendix D – Environmental Report Supplement

This appendix satisfies the requirements of 10 CFR 54.23 to provide a supplement to the environmental report that complies with the requirements of subpart A of 10 CFR Part 51.

Appendix E ***– Required Technical Specification Changes***

This appendix satisfies the requirement in 10 CFR 54.22 to identify technical specification changes or additions necessary to manage the effects of aging during the period of extended operation.

One Technical Specification change will be required in order to revise the vessel pressure-temperature curves to account for the effects or irradiation of the core beltline over the extended operating period.

1.6 DEFINITIONS

SNC terminology used in this document is defined below. In addition, definitions for the terms CLB, IPA, and TLAA are provided in 10 CFR 54.3.

Active: As used in relation to a structure, component, or commodity group, the performance of a function with either moving parts or a change in configuration or properties. Examples of active components include pumps (except casings), motors, valves (except bodies), etc. Additional examples may be found in 10 CFR 54.21.

Aging Effect: A change in a system, structure, or component's performance, or change in physical or chemical properties resulting in whole or part from one or more aging mechanisms that degrade the ability of a system, structure, or component to perform its function. Examples include loss of material, cracking, and material property changes.

Aging Mechanisms: The physical or chemical processes that result in degradation. These mechanisms include, but are not limited to fatigue, erosion, corrosion, thermal and radiation embrittlement, microbiologically influenced corrosion, creep, and shrinkage. Aging mechanisms produce aging effects.

Commodity Group (CG) (also Commodity): A grouping of a select number of structures, components, or commodities, based upon considerations such as physical configuration, intended use, materials of construction, environment, management programs, or common aging effects. Commodity groups may be addressed by a single aging management review, when applicable, to achieve efficiency in the aging management review process.

Component: The major structural, mechanical, and/or electrical elements of a system or structure.

Component Function: The specific function of the structure or component that supports an intended function.

Component Group: A grouping of like components. Similarity of components is determined based on component type, component function, materials of construction, and internal and external environments, as applicable. Component groups are uniquely defined for each intended function evaluation boundary. Each component group only contains one component type.

Component Type: A descriptive label used to distinguish different components from each other. The label is usually the same as the common name for the component. For example, “valve” is a component type. Thus, all valves, regardless of brand or other distinguishing features, belong to the “valve” component type.

Consumables: Piece parts of components that are replaced as a normal part of ongoing maintenance activities. Examples include packing, gaskets, sealing material, and O-rings.

Equipment Location Index (ELI): A Plant Hatch controlled and periodically updated list of major plant equipment that gives the equipment master parts list (MPL) number, a brief description, location by column line and elevation, major drawings associated with the equipment, quality classification codes, vendor specifications, and purchase order numbers.

Environmental Qualification Master List: The Plant Hatch list of all equipment included in the 10 CFR 50.49 Environmental Qualification Program. The list includes equipment with individual MPL numbers, as well as commodity items such as cables, splices, and seals.

Evaluation Boundary: The portion of a system or structure, and its related components, that is necessary to accomplish an intended function. The intent in defining an evaluation boundary is to quickly focus the aging management review on the set of structures and components that directly contribute to the successful completion of the system's or structure's intended function. This boundary may or may not match the system or structure boundary traditionally described in plant documents.

Intended Function: The function(s) that is the basis for including the system, structure, or component within the scope of the Rule as specified in 10 CFR 54.4(a). This definition is unique and only applies to implementing the requirements of the Rule.

In-Scope: A term applied to structures, systems, components, or commodities determined to be subject to the requirements of 10 CFR 54.

Long-lived: An item that is not subject to replacement based on a qualified life or specified time period.

Maintenance Rule Scoping Manual: The Plant Hatch document that identifies systems and system functions included in the scope of the Maintenance Rule, 10 CFR 50.65.

Operating Term: 40 years, or as otherwise specified in the plant’s operating license.

Passive: As used in relation to a structure, component, or commodity group, the performance of a function without moving parts or without a change in configuration or properties. Examples include the reactor vessel, the reactor coolant pressure boundary, etc.

Short-lived: An item that is either subject to replacement based upon a qualified life or specified time period.

Spaces: A term used in the electrical component and commodity evaluation process that describes a plant room or boundary for an electrical aging management review. “Spaces” also refers to the evaluation approach described more fully in Sandia National Laboratory Report SAND 96-0344.

Structure: A building or structural assembly that supports and/or encloses systems and/or components.

System: Any collection of equipment that is configured and operated to serve one or more functions (e.g., provide water to the torus, spray water into the containment, inject water into the primary pressure boundary).

System Evaluation Document (SED): A Plant Hatch controlled document issued for the purpose of defining safety-related equipment. It is composed of a written description of safety-related systems**,** including identification of primary system operating modes, and the Safety-Related Components List (SCL).

ACRONYMS

ACRONYM	DEFINITION
ADS	Automatic Depressurization System
AMR	Aging Management Review
ASME	American Society of Mechanical Engineers
ATTS	Analog Transmitter Trip System
ATWS	Anticipated Transient Without Scram
BWR	Boiling Water Reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Program
CAV	Crack Arrest Verification
CCW	Closed Cooling Water
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CRD	Control Rod Drive
CS	Core Spray
CST	Condensate Storage Tank
DBA	Design Basis Accident
DBE	Design Basis Event
DOE	U.S. Department of Energy
ECCS	Emergency Core Cooling System
ECP	Electrochemical Corrosion Potential
EDG	Emergency Diesel Generator
EFPY	Effective Full Power Year
EHC	Electro-Hydraulic Control
ELI	Equipment Location Index
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQRE	Environmental Qualification Report Evaluation
ESF	Engineered Safety Features
FAC	Flow Accelerated Corrosion
FHA	Fire Hazards Analysis
FSAR	Updated Final Safety Analysis Report
GPC	Georgia Power Company
HCU	Hydraulic Control Unit

ACRONYM	DEFINITION
HELB	High Energy Line Break
HNP	Hatch Nuclear Plant
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilation, and Air-Conditioning
HWC	Hydrogen Water Chemistry
IASCC	Irradiation Assisted Stress Corrosion Cracking
IGA	Intergranular Attack
IGSCC	Intergranular Stress Corrosion Cracking
IPA	Integrated Plant Assessment
ISI	Inservice Inspection
IST	Inservice Testing
LLS	Low Low Set
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
MCC	Motor Control Center
MCREC	Main Control Room Environmental Control
MEAG	Municipal Electric Authority of Georgia
MIC	Microbiologically Influenced Corrosion
MOV	Motor-Operated Valve
MPL	Master Parts List
MSIV	Main Steam Isolation Valve
NEI	Nuclear Energy Institute
NPRDS	Nuclear Plant Reliability Data System
NRC	U.S. Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
P&ID	Piping and Instrumentation Diagram
PSW	Plant Service Water
QA	Quality Assurance
QA/CAP	Quality Assurance/Corrective Actions Program
QDP	Qualification Data Package
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RHR	Residual Heat Removal

ACRONYM	DEFINITION
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RTD	Resistance Temperature Detector
RWCU	Reactor Water Cleanup
SBO	Station Blackout
SCC	Stress Corrosion Cracking
SED	System Evaluation Document
SER	Safety Evaluation Report
SGTS	Standby Gas Treatment System
SMP	Structural Monitoring Program
SNC	Southern Nuclear Operating Company
SOC	Statement of Considerations
SRP-LR	Standard Review Plan - License Renewal
SRV	Safety Relief Valve
TLAA	Time-Limited Aging Analyses

1.7 GENERAL REFERENCES

1. 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” 56 FR 64976, December 13, 1991.
2. 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” 60 FR 22491, May 8, 1995.
3. “NEI 95-10, Revision 0, Industry Guideline on Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,” March 1996.
4. 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” 56 FR 31324, July 10, 1991.
5. 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.”
6. “License Renewal Demonstration Program: NRC Observations and Lessons Learned,” NUREG 1568, December 1996.
7. NEI/NRC License Renewal Work Shop, Reference Documents, October 29, 1997.
8. “License Renewal Demonstration Program Site Visit, Hatch Nuclear Power Plant Trip Report,” July 9, 1996.
9. “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses,” Draft Regulatory Guide DG 1047.
10. 10 CFR 50.48, “Fire Protection.”
11. 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants,” 48 FR 2733, January 21, 1983, as amended by 49 FR 45576, November 19, 1984; 51 FR 40308, November 6, 1986; 51 FR 43709, December 3, 1986; 52 FR 31611, August 21, 1987; 53 FR 19250, May 27, 1988; 61 FR 39300, July 29, 1996; 61 FR 65173, December 11, 1996; 62 FR 47271, September 8, 1997.
12. 10 CFR 50.62, “Requirements for Reduction of Risk From Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants,” 49 FR 26044, June 26, 1984; 49 FR 27736, July 6, 1984, as amended by 51 FR 40310, November 6, 1986; and 54 FR 13362, April 3, 1989.
13. 10 CFR 50.63, “Loss of All Alternating Current Power,” 53 FR 23215, June 21, 1988.
14. 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events,” 56 FR 22304, May 15, 1991.
15. “Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors,” Regulatory Guide 1.154.
16. “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants,” Working Draft, September 1997.
17. “Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Terminations,” SAND 96-0344, United States Department of Energy.

Section 2

STRUCTURES AND COMPONENTS REQUIRING AGING MANAGEMENT REVIEW

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2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 INTRODUCTION

This section describes the process that Southern Nuclear (SNC) used to implement the scoping requirements of Title 10 Code of Federal Regulations (CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants, the License Renewal Rule" (Ref. 1) (the "Rule"), as specified in 10 CFR 54.21(a)(2). The specific method SNC used to identify inscope functions and to screen the systems, structures, and components required to perform the inscope functions was developed considering the requirements of the Rule, the Statements of Considerations for the Rule, and the guidance provided by the Nuclear Energy Institute's (NEI) document, NEI 95-10, Revision 0, "Industry Guideline on Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," (Ref. 2). In addition, SNC also considered Nuclear Regulatory Commission (NRC) staff correspondence with other applicants and with the Nuclear Energy Institute in the development of this methodology.

The methodology was also developed with the knowledge that some provisions of the Rule may be satisfied by the plant's action to comply with the Maintenance Rule, 10 CFR 50.65 (Ref. 3). Unless otherwise clarified or modified in the Statements of Considerations accompanying the 1995 amendments to Part 54 (Ref. 4), the Statements of Considerations for the original (1991) Part 54 (Ref. 5) rulemaking remains valid. Therefore, both Statements of Considerations were considered in developing the Plant Hatch scoping and screening process.

The major processes (and applicable Rule sections in square brackets) described in this methodology are as follow:

- Identification of the systems and structures within the scope of the Rule [10 CFR 54.4].
- Identification of the functions of systems and structures determined to be within the scope of the Rule [10 CFR 54.4 and 10 CFR 54.21]. These functions are the intended functions described in 10 CFR 54.4(b).
- Identification of the structures, components, and commodities (SCCs) subject to aging management review [10 CFR 54.21(a)(1)].

The license renewal documents produced using this methodology are subject to the requirements of Part 50, Appendix B (Ref. 6). License Renewal Services internal procedures provide for the control of documents and records, consistent with quality assurance requirements, during the performance of activities described in this methodology. The technical data and results will be maintained in an auditable format and stored in an approved record storage facility.

As used in the Plant Hatch application methodology, scoping is the process of identifying systems and structures that meet the scoping criteria of 10 CFR 54.4(a)(1) - (3), including the identification of intended functions as defined by 10 CFR 54.4(b)— those functions that are related to meeting one or more of the scoping criteria of 10 CFR 54.4(a)(1) - (3). The scoping criteria, with applicable cross references to sections in this document in square brackets, as applied to plant systems, structures, and components, stated briefly, are:

1. Reactor coolant pressure boundary integrity (10 CFR 54.4(a)(1)(i)) [Section *2.1.2.4*].
2. Safe reactor shutdown and maintenance (10 CFR 54.4(a)(1)(ii)) [Section 2.1.2.4].

3. Accident consequences prevention or mitigation (10 CFR 54.4(a)(1)(iii)) [Section *2.1.2.4*].
4. Nonsafety related whose failure could prevent satisfactory accomplishment of any of the functions associated with items 1-3 (10 CFR 54.4(a)(2)) [Section *2.1.2.5*].
5. Compliance with fire protection regulations (10 CFR 50.48) (10 CFR 54.4(a)(3)) [Section *2.1.2.6*].
6. Compliance with environmental qualification regulations for electrical equipment (10 CFR 50.49) (10 CFR 54.4(a)(3)) [Section 2.1.2.6].
7. Compliance with anticipated transients without scram regulations (10 CFR 50.62) (10 CFR 54.4(a)(3)) [Section 2.1.2.6].
8. Compliance with station blackout regulations (10 CFR 50.63) (10 CFR 54.4(a)(3)) [Section 2.1.2.6].

An additional regulation, 10 CFR 50.61, "Fracture toughness requirements for protection against pressurized thermal shock events," does not apply to Plant Hatch, because, as specified in the regulation, an evaluation in accordance with Regulatory Guide 1.154 (Ref. 7) for boiling water reactor plants is not required.

The identification and listing of structures and components subject to an aging management review is called screening in the Plant Hatch application methodology, and is discussed in Section *2.1.3* for civil/mechanical disciplines, and in Section *2.1.4* for the electrical discipline.

Preparation of drawings depicting the set of inscope structures and components is not a rule requirement. However, evaluation boundary drawings for certain intended functions were developed for use during the screening process. Creation and use of these intended function evaluation boundaries is a part of the screening process employed by SNC. However, these drawings are not a part of this application. The intended function evaluation boundary drawings were used as an aid to facilitate identifying the portions of the systems and structures within the scope of the Rule. See Section 2.1.3.1 for the discussion of intended function evaluation boundaries for civil/mechanical disciplines, and Section 2.1.4 for electrical component screening. Because a plant "spaces" approach was used for electrical components, electrical function boundary drawings were produced only in a few instances to support determination of a specific set of components to be brought in scope.

2.1.2 SCOPING

2.1.2.1 Plant Hatch Systems, Structures, and Intended Functions

10 CFR 54.4 defines the requirements for identifying the systems and structures and their intended functions within the scope of the Rule. As provided in 10 CFR 54.4(a)(1), design basis events for license renewal are applied as defined in 10 CFR 50.49(b)(1), consistent with the Hatch CLB. Section 54.4(b) provides that "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 10 CFR 54.4(b).

The SNC process for implementing the requirements of 10 CFR 54.4(a) and (b) is summarized by the following steps and described in detail in this Section (2.1.2):

- Plant systems and structures, and their functions were identified.

- Each system and structure function was reviewed to determine whether it met any of the scoping criteria specified in 10 CFR 54.4(a).

If the system or structure function met one or more of the scoping criteria in 10 CFR 54.4(a), then it is within the scope of the Rule and was designated as an intended function as identified in 10 CFR 54.4(b). In most cases, the intended functions of a system or structure are only a subset of all its functions. Most systems and structures also perform other functions that do not meet any of the criteria in 10 CFR 54.4(a). Only the portions of the systems or structures required to support the intended functions are within the scope of the Rule.

Figure 2.1.2-1 presents a simple flow diagram to depict this process.

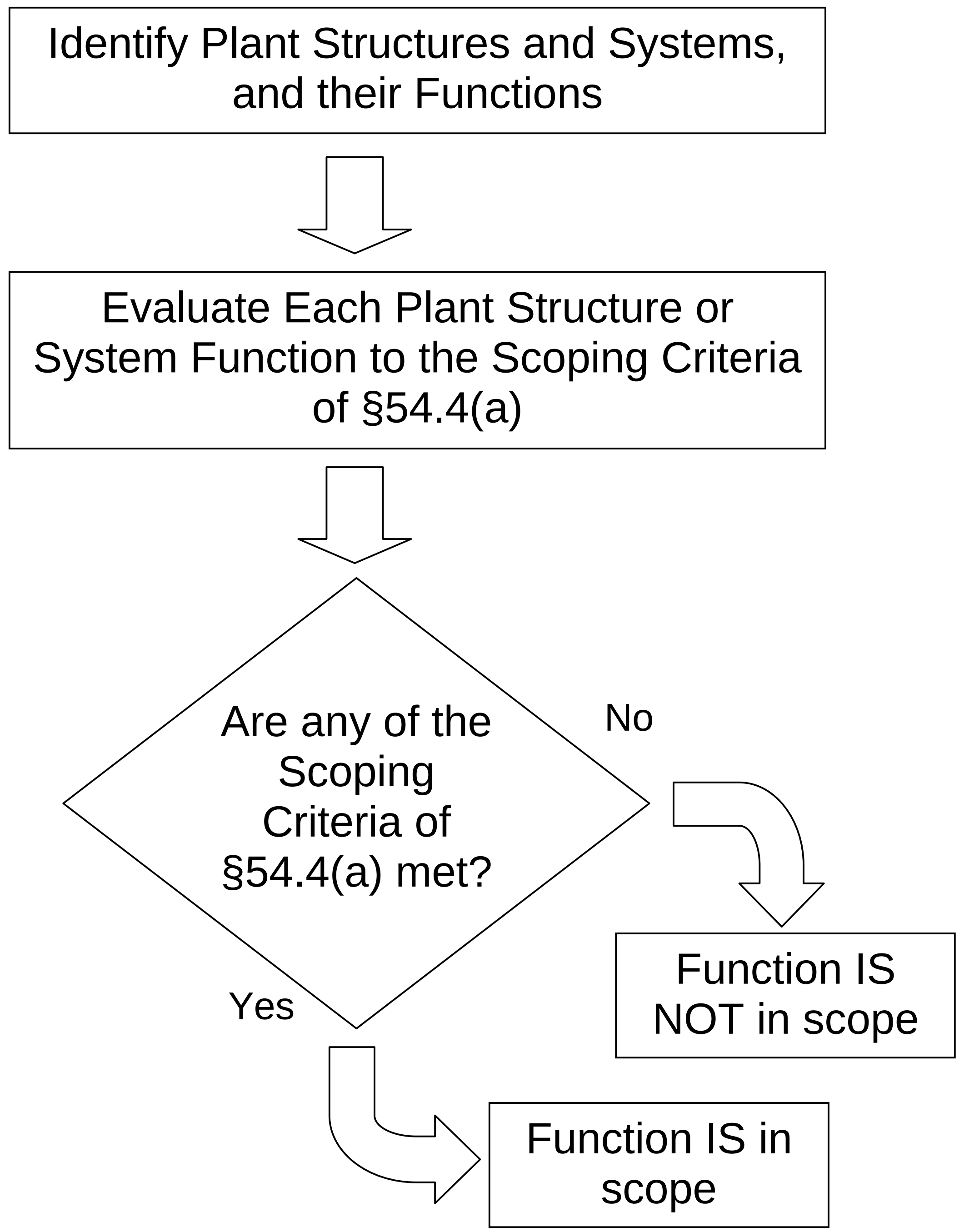


Figure 2.1.2-1 Process Flow Diagram For Plant Hatch License Renewal Scoping

2.1.2.2 System/Structure Function Identification

SNC performed a comprehensive review of design documents in order to create a list of systems and structures to be scoped. Information sources included the Plant Hatch Equipment Location Index (ELI) listing of system and structure nomenclature used at the plant, the Plant Hatch Maintenance Rule Scoping Manual, the Plant Hatch System Evaluation Document (SED), and the Plant Hatch Final Safety Analysis Reports (FSAR). In addition, a plant design drawing which lays out a generic listing of system nomenclature for boiling water reactors (BWR) was reviewed in order to thoroughly identify all potential system/structure identifiers (MPL numbers). The resultant list of potential systems and structures provided a starting point for system and structure function identification.

The scoping requirements of the Rule and the Maintenance Rule overlap. The requirements [10 CFR 54.4(a)(1) and 10 CFR 50.65(b)(1), respectively] for identifying safety-related system and structure functions are similar. In addition, the requirement in 10 CFR 54.4(a)(2) for identifying nonsafety-related system and structure functions within the scope of the Rule is similar to the corresponding requirement [10 CFR 50.65(b)(2)(ii)] in the Maintenance Rule except for issues such as Seismic II/I considerations. Because of the similarities in the rules, the Plant Hatch Maintenance Rule Scoping Manual was one of the information sources used to establish an initial listing of plant system and structure functions.

The final list of functions evaluated encompasses all plant systems and structures, except as described in Section 2.1.2.3. The functions did not necessarily follow traditional system boundaries, in that the functions included structures and components, irrespective of traditional system nomenclature, that perform or support the identified function.

The Rule is a component-based rule. That is, an aging management evaluation down to the component level is required. In addition, the Rule is function oriented. To arrive at the component level, SNC chose to scope at a function level and screen at the component level. SNC has elected to use the term "component function" when referring to the specific structure, component, or component group functions needed to support an intended function. Table 2.1-2 is a listing of component functions defined and used by the Plant Hatch application methodology. Components, component groups, and component functions are addressed in more detail in Section *2.1.3.2*.

2.1.2.3 Excluded Systems and Structures

The list of plant system and structure functions is intended to be comprehensive. However, processing every aspect of the plant was beyond the intent of the Rule. Some practical considerations were employed in the scoping process. That is, some facilities, structures, and equipment were excluded using expert judgment. Examples of excluded facilities, structures, and equipment include the following:

- Driveways and parking lots that provide access to and from various areas of the plant.
- Office and warehouse facilities.
- Temporary equipment.
- Health physics equipment.
- Portable radios.
- Portable measuring and testing equipment and tools.

- Spare parts (however, staged equipment is not excluded from scoping).
- Motor vehicles.

In the Statements of Considerations, the NRC determined that regulatory requirements provide reasonable assurance that an acceptable level of emergency preparedness exists at any operating reactor at any time in its operating lifetime. Similarly, in the Statements of Considerations, the NRC determined that regulatory requirements for physical protection provide reasonable assurance that an adequate level of physical protection exists at any operating reactor at any time in its operating lifetime. For those reasons, the Statements of Considerations indicated the Commission will make no new finding on emergency preparedness or physical protection (security) as part of a license renewal decision. Thus, Plant Hatch systems and structures that only provide emergency preparedness or physical protection functions were not evaluated in the Plant Hatch scoping process.

2.1.2.4 Safety-Related Systems and Structures

10 CFR 54.4(a)(1)(i, ii, and iii) provide the scoping criteria for determining the functions of safety-related systems and structures that are within the scope of the Rule. Each system and structure function in the plant listing of scoping results (Table 2.2-1) was reviewed with respect to these requirements by addressing the following questions:

- Is the system or structure function identified as safety related because it is relied upon during and following design basis events to ensure the integrity of the reactor coolant pressure boundary?
- Is the system or structure function identified as safety related because it is relied upon during and following design basis events to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition?
- Is the system or structure function identified as safety related because it is relied upon during and following design basis events to ensure the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 100.11?

Engineering and licensing documents were used to answer these questions. The ELI and the SED are engineering documents that provide system-related design information. The FSARs, the Maintenance Rule Scoping Manual, and the SED provide function-related information. The FSARs and applicable references identify the basis for Plant Hatch design basis events.

If the answer to one or more of the three questions was "YES," the corresponding system or structure function was determined to be within the scope of the Rule and was designated as an intended function as identified by 10 CFR 54.4(b).

SNC, in certain cases, has conservatively chosen to designate some systems whose functions may not meet any of the scoping criteria of 10 CFR 54.4(a)(1) as safety related. In such cases, the inscope determination may indicate that the system function does not meet the scoping criteria of 10 CFR 54.4(a)(1). System functions brought into scope by 10 CFR 54.4(a)(1) were also reviewed to determine whether they were also in scope based on the requirements of 10 CFR 54.4(a)(2) or 10 CFR 54.4(a)(3). In addition, functions may include, in a few cases, both safety-related and nonsafety-related components. In those cases, a function would be identified as meeting the scoping criteria of 10 CFR 54.4(a)(1) as well as the requirement for 10 CFR 54.4(a)(2), as described in the following Section.

2.1.2.5 Nonsafety-Related Systems and Structures Whose Failure Could Prevent Safety-Related Systems and Structures from Accomplishing Their Function

The scoping criterion at 10 CFR 54.4(a)(2) was used to identify the functions of nonsafety-related systems and structures that are within the scope of the Rule. 10 CFR 54.4(a)(2) provides that "all nonsafety-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)" of Section 54.4 are within the scope of the Rule. Few system and structure functions at Plant Hatch satisfy the criterion because systems and structures supporting safety-related systems and structures were typically designed as safety-related. Each system and structure function in the plant listing of scoping results was reviewed with respect to this requirement by addressing the following question:

- Is the system or structure function identified as nonsafety related whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i, ii, and iii)?

Engineering and licensing documents were used to answer this question. The ELI and the SED were used to provide system-related design information. The FSARs, the Maintenance Rule Scoping Manual, and the SED were used to provide function-related information. The FSARs and applicable references were used to identify the basis for Plant Hatch design basis events.

Based upon a review of the Plant Hatch Final Safety Analysis Reports, issues or events considered in association with this question for Plant Hatch were Seismic II/I, flooding, jet impingement, pipe whip, and missiles.

If a function was used to mitigate one or more of the issues or events, the answer to the above question was "YES," the corresponding system or structure function was brought inscope, and the function was identified as an intended function per 10 CFR 54.4(b). In making determinations associated with this question, SNC also relied on the consideration of actual plant-specific experience, industrywide operating experience, and existing plant-specific engineering evaluations that were originally addressed by the controlled Maintenance Rule Scoping Manual determinations. Consistent with the Statements of Considerations, hypothetical failures that result from postulated system functional interdependencies that are not part of the Plant Hatch safety analyses or effects evaluations and that have not been observed at Plant Hatch were not considered.

2.1.2.6 Systems and Structures Relied Upon to Demonstrate Compliance With Certain NRC Regulations

SNC reviewed NRC Safety Evaluation Reports (SERs) and related docketed correspondence associated with four of the five regulations called out in 10 CFR 54.4(a)(3). SNC used this review to identify the set of system and structure functions credited with satisfying the requirements associated with those regulations from the complete set of system and structure functions established by the process described in Section 2.1.2.2. The four regulations are as follow:

- 10 CFR 50.48, "Fire protection."
- 10 CFR 50.49, "Environmental qualification of electric equipment important to safety for nuclear power plants."

- 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants."
- 10 CFR 50.63, "Loss of all alternating current power."

An additional regulation, 10 CFR 50.61, "Fracture toughness requirements for protection against pressurized thermal shock events," does not apply to Plant Hatch, because, as specified in the regulation, an evaluation in accordance with Regulatory Guide 1.154 (Ref. 7) for boiling water reactor plants is not required.

Each system and structure function was reviewed with respect to these criteria by addressing the following questions:

- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for fire protection (10 CFR 50.48)?
- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for environmental qualification (10 CFR 50.49)?
- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for ATWS events (10 CFR 50.62)?
- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for SBO (10 CFR 50.63)?

The Environmental Qualification Master List (EQML) was used to identify the systems relied upon to comply with 10 CFR 50.49. For the second question, if system or structure components were listed in the EQML, then the system or structure function(s) that required environmental qualification of the components was designated as being relied upon to demonstrate compliance with 10 CFR 50.49. These system or structure functions were brought in scope and they were identified as intended functions per 10 CFR 54.4(b).

During the review of the EQML, NRC SERs, and docketed correspondence, SNC confirmed that any credited functions and the systems and structures that specifically contribute to accomplishing the functions were included in the list of system or structure functions.

For the remaining questions, regarding the fire protection, ATWS, and station blackout regulations, if the answer to any of the questions was "YES," then the corresponding system or structure function(s) was brought into scope and the function(s) was identified as an intended function per 10 CFR 54.4(b). The NRC SERs and associated docketed correspondence were used to answer these questions.

References to a system, structure, or function in a SER or docketed correspondence were evaluated to determine whether the system, structure, or function was required to comply with the regulation. Functions and the associated systems and structures were excluded if they were not specifically used in the analyses or evaluations to assure compliance with the regulation. In addition, consistent with the Statements of Considerations III(c)(iii), new evaluations which consider additional systems and structures required to support operability of these systems and structures were not performed, nor was consideration taken of hypothetical failures that could result from system interdependencies that are not part of the Plant Hatch safety analyses and have not been previously experienced at Plant Hatch.

2.1.3 CIVIL/MECHANICAL COMPONENT SCREENING

The Rule requires a review of plant systems, structures, and components to determine if the effects of aging are adequately managed for certain structures and components in the period of extended operation. The process described in Section 2.1.2 was used to identify the Plant Hatch intended functions, that is, those system, structure, and component functions that are within the scope of the Rule. The Rule then requires, at 10 CFR 54.21(a), that an integrated plant assessment process be applied to systems, structures, and components determined to be in scope per 10 CFR 54.4. The integrated plant assessment process employed by SNC required an initial review of those functions within the scope of the Rule, as determined by the process described in Section 2.1.2, to define intended function evaluation boundaries. The intended function evaluation boundaries were then used to assist in the identification of the structures and components that are subject to an aging management review. That portion of the integrated plant assessment which describes the process used to identify civil/mechanical structures and components subject to an aging management review (screening) is described in this Section. Section 2.1.4 describes the screening of electrical components.

The Rule, at 10 CFR 54.21(a)(1), requires applicants to identify and list the structures and components subject to an aging management review. This section defines a "screening" process whereby SNC identified and listed the structures and components which met the criteria of 10 CFR 54.21(a)(1)(i) and (ii). Use of the term "passive" within this application is intended to be identical to criterion (i). That is, structures and components that perform an intended function without moving parts or without a change in configuration or properties are characterized in this document as "passive." Likewise, as set forth in criterion (ii), structures and components that are not subject to replacement based on a qualified life or specified time period are characterized in this document as "long-lived."

SNC performed screening of the civil/mechanical intended functions for Plant Hatch in two steps:

1. Evaluation boundaries were established for each intended function; and
2. Passive, long-lived components were identified within each evaluation boundary.

The screening process first established an evaluation boundary to define the systems or structures that are required to accomplish an intended function. Then each evaluation boundary was used to assist in identification of the complete set of structures and components within the evaluation boundary and to identify the passive, long-lived subset that represents those structures and components subject to an aging management review. This final set of structures and components is presented in the tables in Sections 2.3 through 2.5 in fulfillment of the requirement of 10 CFR 54.21(a)(1).

2.1.3.1 Intended Function Evaluation Boundaries

This step of the screening process defines the evaluation boundary for the system and structure functions determined to be within the scope of the Rule by the process described in Section 2.1.2. These functions are the intended functions per the definition in the Rule at 10 CFR 54.4(b). Defining the evaluation boundary focuses the screening process on the portions of systems and structures that contribute to the performance of one or more intended functions. Evaluation boundaries were established such that multiple, inscope functions are included in one evaluation boundary description to the extent practical. Evaluation boundaries were produced using controlled procedures to assure a consistent approach to preparation and documentation.

Evaluation boundaries, as used in this methodology, were not required to match other boundaries that are defined in existing documents such as the FSARs or plant piping and instrumentation diagrams. Defining evaluation boundaries for license renewal does not require the plant to change or redefine other existing boundaries such as pipe class design boundaries or In-Service Inspection and Testing boundaries. In addition, where a functional boundary was defined in the CLB for an inscope function, the CLB-defined boundary was used. SNC chose to conservatively designate certain components as “in scope” more broadly than the rule might otherwise require. In such cases, the intended function evaluation boundaries do not redefine the CLB.

The method of describing the evaluation boundary relied primarily on plant drawings. The set of drawings that were most appropriate to illustrate the boundary information was marked up with boundary designations that clearly indicate which portions or areas of the system are inside and which portions are outside the evaluation boundary. For example, system piping and instrumentation diagrams (P&ID) were typically used to illustrate the evaluation boundary of intended functions from a mechanical perspective.

Due to the nature of civil/structural functions, evaluation boundary drawings were not produced for intended functions associated with structures; piping, cable tray, and conduit supports; electrical panel and rack supports; secondary containment doors; cranes; tornado vents; and penetrations. Instead, a plan view of the plant site was produced to identify the inscope structures. The evaluation boundary of a structure that is a building included the entire building, including slabs, external and internal walls, roof and internal concrete, steel columns and beams, and framing. Miscellaneous steel items, such as base plates and embedded plates, were also included.

In the process of defining evaluation boundaries, emphasis was placed on assuring all interfaces were adequately considered. As necessary, other references, prepared lists, and written descriptions were used to supplement or further clarify the boundary designations on the marked-up drawings. The final set of illustrated mechanical and electrical drawings, references, and written descriptions formed the "boundary package" for an intended function and was documented by controlled procedures.

In order to maintain a consistent approach to screening, general and specific discipline interface guides were established and used to assist in designating the intended function evaluation boundaries and interfaces. The guidelines were incorporated into a controlled procedure for component screening. The guidance was not established, however, as a set of rigid requirements. Specific cases were dispositioned on the basis of producing a conservative boundary.

The SNC screening process first defined civil/mechanical evaluation boundaries for intended functions. Then, all components included in the evaluation boundary were grouped, when practical, and screened. This approach differs from NEI 95-10, Revision 0, which establishes groupings after the screening process is completed.

2.1.3.2 Component Types, Component Groups, and Component Functions

Table 2.1-1 lists component types that are in scope for license renewal at Plant Hatch. This table is based on a table that originated as Appendix B of NEI 95-10, Revision 0. That listing was revised and expanded by the NEI License Renewal Task Force to include component types, mostly electrical, that were omitted from the original Appendix B. During the process of screening structures and components at Plant Hatch, additional component types were identified and are included in Table 2.1-1.

The list in Table 2.1-1 represents the plantwide list of inscope structures and components, by component type. The tables in Sections 2.3 through 2.5 present the screening results arranged by plant system or structure member. Each component type listed in the tables in sections 2.3 through 2.5 is a passive component as determined in Table 2.1-1.

Although not required by the Rule, in order to more efficiently screen structures and components, component types within each intended function evaluation boundary were grouped to the maximum extent practicable. In creating these component groups, only components of the same type were grouped together. That is, a component group of valves did not include pipe. In addition, only component types within each intended function evaluation boundary that were fabricated of similar materials, and which were subjected to similar environments were grouped. For example, stainless steel valves were not grouped with carbon steel valves, and piping with an internal environment of reactor coolant water was not grouped with raw water piping.

Structural or mechanical components included in each component group were identified and documented by one or a combination of the following methods:

- By establishing a list of the MPL numbers;
- By listing the reference drawings; or
- By describing the component or system.

When establishing a passive and long-lived component group, specific information required to accurately describe the component function(s), materials composition, and internal and external environments for the components included in the component group was recorded in the screening records. In addition, the applicable drawings, system descriptions, design information, material specifications, and/or other information that could aid in performing an aging management review was documented to the extent necessary to accurately and efficiently screen a component group.

Component types that did not fit into a component group were recorded separately. In only a few instances, a component group was not created because the component being screened was unique; that is, only one component of the component type being evaluated was found in license renewal scope within the evaluation boundary. The information recorded for these passive and long-lived components and component types included a component function(s), the material designation(s), internal/external environmental conditions, pertinent design information, and pertinent drawings/documents that could aid in performing an aging management review.

Component function(s) for component types subject to an aging management review were established on the basis of how the structure or component functions to support maintaining one or more intended functions consistent with the CLB, without reliance on redundancy or probabilistic considerations. Table 2.1-2 provides the list of component functions used in the structure and component screening at Plant Hatch. This table expands on the list of component functions originally presented in NEI 95-10, Revision 0.

2.1.3.3 Passive Structures, Components, and Component Groups

Having considered the effectiveness of existing plant programs which monitor the performance and condition of systems, structures, and components that perform active functions, the NRC concluded in the Statements of Considerations that active components can be excluded from a license renewal aging management review. This exclusion from license renewal review is because functional degradation resulting from the effects of aging on active components is more readily determined, and existing programs and requirements are expected to directly detect and correct the effects of aging.

Table 2.1-1 presents the active/passive determination made for each inscope component type. The "Determination Basis" column identifies the source, or basis, for the active/passive determination. For those component types that were added to the list during the Plant Hatch screening activity, the basis for the determination is contained in internal documentation and is not presented in the application. Some active/passive determinations presented in Table 2.1-1 are different from the determination presented in Appendix B of NEI 95-10, Revision 0. The Appendix B list indicated the component type to be passive when any aspect of the component's function was subject to an aging management review. Table 2.1-1 presents the determinations in a different way. The nature of the component type is identified in the active/passive determination. For example, a valve is active since movement is required for it to perform its function. Similarly, a door is active since it is designed to open and close. However, when certain features of the component require evaluation, those features are listed parenthetically with the component type label. Specific examples include "bodies only" for valves, "casings only" for pumps, and "pressure boundary only" or "structural integrity only" for numerous component types.

The SNC process defined evaluation boundaries for intended functions associated with structures and screened the boundaries to identify the passive and long-lived elements of the structures. Figure 4.1-1 of the NEI 95-10, Revision 0, guideline excludes structures from the active/passive and long/short-lived component determination process since structural components are generally passive and long-lived. As a matter of convenience, SNC did not make this distinction in the screening of structural components. Although intended function evaluation boundary drawings were not produced for the structures, the structural components screening included the active/passive and long/short-lived determinations as a matter of completeness and to facilitate the aging management reviews.

2.1.3.4 Components Subject to Periodic Replacement at a Set Frequency or Qualified Life

The detrimental effects of aging are assumed to be continuous and incremental. Thus, the detrimental effects of aging may increase as service life is extended, assuming no replacement of components. One way of effectively managing these effects is to replace selected structures and components on a specified time interval, based upon a qualified life of the structure or component. Consistent with the Statements of Considerations of the Rule, it is not necessary to justify or prove that the frequency of replacement is adequate since the existing regulatory processes are credited with ensuring their adequacy.

In this step of the screening process, the passive structures and components were reviewed to determine if they are subject to replacement based upon a specified time or qualified component life. Structures and components that are not subject to such replacement were classified as "long-lived." In the methodology employed by SNC, a replacement life must be less than 40 years for the structure or component to be considered "short-lived." Structures and components with replacement lives of 40 years or greater were considered "long-lived." Structures and components subject to replacement based on qualified life were identified as not being subject to aging management review.

2.1.4 ELECTRICAL COMPONENT SCREENING

This section provides the methodology used for screening of electrical components in accordance with the requirements of the Rule. The purpose of this section is to identify the electrical and I&C components at Plant Hatch which require an AMR for license renewal. This section of the Plant Hatch scoping methodology describes and justifies how the list of electrical components which require an AMR was determined. The process employed in electrical component screening is intended to identify all electrical components in the plant which require an aging management review.

2.1.4.1 Identification of Electrical Components Subject to an Aging Management Review

The process used to identify electrical components subject to an aging management review is different from the method used to identify civil and mechanical components subject to an aging management review. Electrical screening was based on the premise that the majority of electrical components installed in the plant perform their function with moving parts or a change in configuration or properties, and are therefore not subject to an aging management review per the Rule. The electrical screening process was accomplished using the following steps:

1. Develop a comprehensive list of all electrical component types installed in the plant without regard for system function or license renewal inscope status.
2. Determine the basic function each component type performs.
3. Determine which component types perform their function without moving parts or a change in configuration or properties. This results in the list of electrical component types which are subject to an aging management review for license renewal.
4. Apply the scoping criteria of 10 CFR 54.4(a)(1) through (3) to the list of component types which meet the screening criteria to determine if the list of electrical component types requiring an aging management review can be further reduced.

List of Installed Component Types

In order to screen electrical component types to determine those which require an aging management review, a complete list of all electrical component types installed in the plant was required. This list was compiled using the lists of components found in 10 CFR 54.21(a)(1)(i) and NEI 95-10, Appendix B, as the starting point. The NEI 95-10 list was further evaluated and refined by industry working groups. The resulting list of components was evaluated by plant engineering personnel and system experts who used their knowledge of plant systems and drawings to ensure that the list was complete and contained all electrical component types in use at Plant Hatch. Some component types with similar functions were grouped together for simplicity. This process provides reasonable assurance that the list of electrical component types installed in the plant is accurate and complete. The in scope electrical component types installed at Plant Hatch are included in the Table 2.1-1 list. The list of electrical component types subject to an aging management review appears in Table 2.5.15-1.

Application of 10 CFR 54.21 Screening Criteria to Electrical Component Types

Having compiled the electrical component type list, the 10 CFR 54.21 criteria were applied to determine which component types are subject to an aging management review. The screening criteria of 10 CFR 54.21(a)(1)(i) and (ii) were applied to the comprehensive list of electrical component types to accomplish this step. Components for which both criteria are "YES" are subject to an aging management review. These screening criteria are as follow:

- 10 CFR 54.21(a)(1)(i) – The component performs an intended function as described in 54.4 without moving parts or without a change in configuration or properties;
- 10 CFR 54.21(a)(1)(ii) – The component is not subject to replacement based on a qualified life or a specified time period.

An active/passive determination in accordance with 10 CFR 54.21(a)(1)(i) was documented for each type of electrical component installed at Plant Hatch. This determination is presented in Table 2.1-1. The bases for these active/passive screening determinations are provided as a footnote to the table.

When implementing the screening criteria of 10 CFR 54.21(a)(1)(ii), except for those cases where a determination was made for individual components (e.g., components qualified pursuant to 10 CFR 50.49), the determination was made for an entire component type or commodity group.

Individual components within the scope of the EQ program fall into two categories: those with a qualified life of 40 years or greater which are covered by a TLAA, and those with a qualified life of less than 40 years and are therefore subject to replacement based on a specified time period. The components with qualified lives of less than 40 years are currently on a replacement schedule which will continue into the renewal term; these components are not subject to an AMR. The qualified life calculations of those components with qualified lives greater than 40 years are treated as TLAAs and are evaluated in Section 4. These TLAAs are dispositioned in accordance with the applicable disposition method per the Rule. In cases where a particular TLAA cannot be extended to 60 years, those components will be replaced or refurbished in accordance with the requirements of the EQ program. Therefore, no components included in the EQ program are subject to an AMR.

Application of 10 CFR 54.4 Scoping Criteria to Electrical Component Types

Scoping was performed as described in Section 2.1. The set of passive, long-lived component types derived from the process described in Section 2.1.4.1, steps 1 through 3, was then evaluated to the scoping criteria stated in step 4. This step was performed to further define the set of electrical component types subject to aging management review.

The set of electrical component types remaining after steps 1 through 4 of the screening process are included in the list in Table 2.1-1 of Plant Hatch component types subject to aging management review.

2.1.5 DOCUMENTATION

Section 54.37(a) of the Rule requires all information and documentation required, or otherwise necessary, to document compliance with the provisions of the Rule to be retained in an auditable and retrievable form.

Paragraphs 10 CFR 54.21 and 54.37 detail the requirements of the Rule for documenting the IPA process. SNC has complied with these Rule requirements in the preparation of this application.

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations

Component Type	Passive	Determination Basis[1]
Air Compressor	No	1
Alarm Unit	No	2
Analyzers	No	2
Annunciators	No	2
Batteries	No	1
Battery Chargers	No	1
Cable Trays and Supports	Yes	1
Cables	Yes	1
Circuit Breakers	No	1
Controllers – Differential Pressure Indicating Controller	No	2
Controllers – Flow Indicating Controller	No	2
Controllers – Manual Loader	No	6
Controllers – Other	No	2
Controllers – Programmable Logic Controller	No	6
Controllers – Single Loop Digital Controller	No	6
Controllers – Speed Controller	No	2
Controllers – Temperature Controller	No	2
Controllers – Valve Positioner	No	6
Converters – Amp Transducer	No	6
Converters – Current/Pneumatic Converter	No	6
Converters – Frequency Transducer	No	6
Converters – Other	No	6
Converters – Power Factor Transducer	No	6
Converters – Signal Converter	No	6
Converters – Signal Selector, Hi/Lo	No	6
Converters – Speed Transducer	No	6
Converters – Square Root Extractor	No	6
Converters – Summer	No	6
Converters – VAR Transducer	No	6
Converters – Vibration Transducer	No	6

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Converters – Voltage Transducer	No	6
Converters – Voltage/Current Converter	No	2
Converters – Voltage/Pneumatic Converter	No	2
Converters – Watt Transducer	No	6
Dampers	No	1
Doors, controlled leakage and fire-rated barriers (pressure boundary, structural integrity)	No	2
Electric Heaters (pressure boundary only)	No	3
Electrical Connectors	Yes	1
Electrical Panels, Racks, Cabinets, & Other Enclosures (structural integrity only)	No	1
Electronic Devices	No	6
Emergency Diesel Generators	No	1
Emergency Lighting	No	2
Fan-Coil Unit	No	5
Fans – Ventilation Fans	No	1
Fire Barriers	Yes	2
Fire Pump Diesel Engines	No	1
Flexible Connectors	Yes	2
Fuel Assemblies	No	5
Fuel Pool and Sump Liners	Yes	1
Fuses	No	4
Grounding	Yes	6
Hangers and Supports, ASME Class 1	Yes	1
Hangers and Supports, Non-ASME Class 1	Yes	1
Heat Exchangers	Yes	1
Heat Tracing	No	3
Hose Stations	Yes	2
Indicators – Ammeter	No	2
Indicators – Conductivity Meter	No	6
Indicators – Differential Pressure Indicator	No	1
Indicators – Flow Indicator	No	2

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Indicators – Frequency Meter	No	6
Indicators – Level Indicator	No	1
Indicators – Other	No	6
Indicators – Power Factor Meter	No	6
Indicators – Pressure Indicator	No	1
Indicators – Speed Indicator	No	2
Indicators – Temperature Indicator	No	2
Indicators – VAR Meter	No	6
Indicators – Vibration Indicator	No	6
Indicators – Volt Meter	No	6
Indicators – Watt Meter	No	6
Indicators – Watthour Meter	No	6
Installed Communication Equipment	No	5
Instrument Racks, Frames, Panels, & Enclosures (structural integrity only)	No	1
Insulation, Thermal	Yes	5
Isolators	No	2
Joints and Seals, Compressible	Yes	2
Local Starter	No	2
Magnetic Contactor	No	2
Motor-Generator Sets	No	2
Motors	No	1
Panels – Distribution Panel Internal Component Assemblies (structural integrity only)	No	2
Panels – Electrical Controls and Panel Internal Component Assemblies (structural integrity only)	No	2
Penetration Assemblies, Electrical and I&C	Yes	1
Penetration Seals	Yes	2
Penetrations – Nelson Frames	Yes	5
Phase Bussing – Isolated Phase Bus	Yes	5
Phase Bussing – Metal Enclosed Bus	Yes	5
Phase Bussing – Non-Segregated Phase Bus	Yes	5

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Phase Bussing – Other	Yes	5
Piping – Class 1 Piping Components	Yes	1
Piping – Non-Class 1 Piping Components	Yes	1
Power Distribution - AC Motor Control Center	No	2
Power Distribution - DC Motor Control Center	No	2
Power Distribution - Load Center	No	2
Power Distribution - Other	No	6
Power Distribution - Switchgear Unit	No	1
Power Supply	No	1
Pumps (casings only)	No	1
Reactor Vessel	Yes	2
Reactor Vessel Internals	Yes	2
Recombiners	No	5
Recorders	No	2
Refrigerant Condensing Unit	No	5
Regulators - Current Regulator	No	6
Regulators - Frequency Regulator	No	6
Regulators - Other	No	6
Regulators - Voltage Regulator	No	6
Relays - Auxiliary Relay	No	1
Relays - Control Logic Relay	No	1
Relays - Other	No	1
Relays - Protective Relay	No	1
Relays - Time Delay Relay	No	1
Restricting Orifices	Yes	2
Rupture Disks (pressure boundary)	No	2
Sensors - Conductivity Element (pressure boundary only)	No	2
Sensors - Flow Element (pressure boundary only)	No	2
Sensors - Moisture Sensor	No	6
Sensors - Other (pressure boundary only)	No	6
Sensors - Radiation Sensor (pressure boundary only)	No	2

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Sensors - Temperature Sensor (pressure boundary only)	No	2
Sensors - Vibration Probe (pressure boundary only)	No	6
Signal Conditioners	No	2
Smoke Detectors	No	6
Snubbers	No	1
Steam Traps (pressure boundary only)	No	2
Strainers	Yes	2
Structural Bellows	Yes	2
Structures - Category 1	Yes	1
Structures - Equipment Supports and Foundations	Yes	1
Structures - Non Category 1 Intake Structures	Yes	2
Structures - Offgas Stack and Flue	Yes	2
Structures - Other Non-Category 1 Structures	Yes	2
Structures - Primary Containment	Yes	1
Switches - Automatic Transfer Switch	No	1
Switches - Conductivity Switch	No	1
Switches - Control Switch	No	1
Switches - Current Switch	No	1
Switches - Differential Pressure Indicating Switch	No	1
Switches - Differential Pressure Switch	No	1
Switches - Flow Switch	No	1
Switches - Fusible Disconnect Switch	No	1
Switches - Knife Switch	No	1
Switches - Level Indicating Switch	No	1
Switches - Level Switch	No	1
Switches - Limit Switch	No	1
Switches - Manual Transfer and Disconnect Switch	No	1
Switches - Moisture	No	1
Switches - Other	No	1
Switches - Position Switch	No	1
Switches - Pressure Indicator Switch	No	1

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Switches - Pressure Switch	No	1
Switches - Safety Switch	No	1
Switches - Temperature Indicating Switch	No	1
Switches - Temperature Switch	No	1
Switches - Vibration Switch	No	1
Tanks	Yes	2
Timers	No	6
Transformers - Instrument Transformer	No	3
Transformers - Load Center Transformer	No	3
Transformers - Other	No	6
Transformers - Small Distribution Transformer	No	3
Transmitters - Conductivity Transmitter	No	6
Transmitters - Differential Pressure Transmitter	No	1
Transmitters - Flow Transmitter	No	2
Transmitters - Level Transmitter	No	2
Transmitters - Other	No	6
Transmitters - Pressure Transmitter	No	1
Transmitters - Radiation Transmitter	No	2
Transmitters - Temperature Transmitter	No	6
Transmitters - Valve Position Transmitter	No	6
Tube Track	Yes	2
Turbines - Turbine Pump Drive Casings (excluding pumps)	Yes	2
Unit Heater	No	3
Valve (bodies only)	No	1
Valve Operators (hydraulic, motor, air, solenoid)	No	2

[1]Determination Bases

1. The Rule, at 10 CFR 54.21(a)(1)(ii), excludes a variety of electrical and I&C components from an aging management review. The specific items are listed in this section. If a determination for a particular component type is presented in the Rule, no further evaluation is deemed necessary.
2. NEI 95-10 provides an active/passive determination for many of the items on the list. This information has been previously reviewed and approved by industry groups; if a determination for a particular component type is presented in NEI 95-10, and this determination has been accepted by the industry and the Nuclear Regulatory Commission, no further evaluation is deemed necessary.
3. The letter from the Nuclear Regulatory Commission to the Nuclear Energy Institute dated September 19, 1997, provided evaluations for transformers, heat tracing, electric heaters, indicating lights, and recombiners.
4. The letter from the Nuclear Regulatory Commission to the Nuclear Energy Institute dated April 27, 1999, provided clarification of the status of fuses and is used as the basis for the determination that fuses do not require an aging management review.
5. Plant-specific evaluations were performed for these component types.
6. Certain components listed on Table 2.1-1 are variations of equipment evaluated by NEI 95-10 or listed in 10 CFR 54.21(a)(1)(i). These components perform the same basic function as those that are evaluated and have the same active/passive determination as the listed components.

Table 2.1-2 List of Component Functions

Label	Description
1. Debris Protection	Provide protection from debris
2. Environmental Control	Provide environmental control of plant areas not to exceed equipment limitations
3. Exchange Heat	Provide exchange of heat from one fluid medium to another
4. Fire Barrier	Provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
5. Fission Product Barrier	Provide pressure boundary or fission product retention barrier to protection public health and safety in the event of any postulated DBEs
6. Flood Barrier	Provide flood protection barrier (internal and external flooding event)
7. Flow Direction	Provide spray shield or curbs for directing flow
8. Flow Distribution	Provide flow pattern or distribution
9. Flow Restriction	Provide flow restriction or pressure reduction or fixed throttling of process flow
10. HE/ME Shielding	Provide shielding against high energy line breaks and moderate energy line cracks credited in the CLB
11. Insulation Resistance	Provide insulation resistance to preclude shorts/grounds and unacceptable leakage current
12. Missile Barrier	Provide missile barrier (internally or externally generated)
13. Non-S/R Structural Support	Provide structural support to nonsafety-related components whose failure could prevent satisfactory accomplishment of any of the required safety-related functions
14. Pipe Whip Restraint	Provide pipe whip restraint
15. Pressure Boundary	Provide pressure retaining boundary so that sufficient flow and adequate pressure is delivered
16. Radiation Shielding	Provide shielding against radiation
17. Shelter/Protection	Provide shelter/protection to safety-related components
18. Structural Support	Provide structural support to safety-related components

2.2 SCOPING RESULTS

Table 2.2-1 presents the results of the Plant Hatch plantwide scoping of systems/structures and functions. Each function is identified as either in scope or not in scope. Due to the cross-system nature of functions, each function has been assigned to a primary system or structure. However, in many cases the functional boundaries extend into other systems or structures as well. As was described in the scoping/screening methodology, Section 2.1, screening of structures/components was performed within functional boundaries. Structures or other features not bearing a system number were assigned to a system or structure and scoped with that system or structure.

For each system/structure entry in Table 2.2-1 with at least one "inscope" function (these are the intended functions), narrative discussion is provided in Section 2.3, Section 2.4, or Section 2.5. These sections are arranged by mechanical, civil/structural, and electrical disciplines. As background information, a general system description is provided. The narrative also lists the intended functions that were evaluated to identify the set of components supporting those intended functions. Finally, each narrative presents a table of component groups requiring an aging management review. These tables identify and list the structures and components subject to aging management review, as stipulated in 10 CFR 54.21(a)(1). No discussion of systems, structures, functions, or components not in scope is provided in the narratives and tables of Sections 2-3 through 2-5.

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results

System Number	System Name	In Scope	Function Number/Name
A70	Analog Transmitter Trip System	Yes	A70-01 Process Parameter Monitoring
A71	Nuclear Steam Supply Shutoff	Yes	A71-01 Signal Transmission
B11	Reactor Assembly	Yes	B11-01 Nuclear Boiler
		Yes	B11-02 Reactivity Control
B21	Nuclear Boiler System	Yes	B21-01 Pressure Control
		Yes	B21-02 Reactor Coolant Pressure Boundary Integrity
		Yes	B21-03 Rod Worth Minimizer
		Yes	B21-04 Nuclear Boiler Instrumentation
B31	Reactor Recirculation	No	B31-01 Reactivity Control
		Yes	B31-02 RPT Breaker Trip
		Yes	B31-03 Reactor Coolant Pressure Boundary Integrity
C11	Control Rod Drive	No	C11-01 Normal Control Rod Movement
		No	C11-02 Vessel Injection
		No	C11-03 Control Rod Cooling
		Yes	C11-04 Reactivity Control (Reactor Scram)
		No	C11-05 Alternate Boron Injection
		No	C11-06 Pump Seal Purge
		Yes	C11-07 Alternate Rod Insertion (ARI)
C32	Feedwater Control	No	C32-01 Regulate Feedwater Flow to Vessel
C41	Standby Liquid Control	Yes	C41-01 Reactivity Control
		No	C41-02 Vessel Injection
		Yes	C41-03 SBLC Testing
		No	C41-04 SBLC System Draining
C51	Neutron Monitoring System	No	C51-01 Reactivity Monitoring
		No	C51-02 Rod Block Monitor
		No	C51-03 Traversing Incore Probe
C61	Primary Containment Isolation	Yes	C61-01 Primary Containment Isolation & Integrity
		Yes	C61-02 Signal Transmission

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
C71	Reactor Protection System	Yes	C71-01 Reactivity Control
		Yes	C71-02 Power Supply
C82	Remote Shutdown	Yes	C82-01 Alternate Control Room
C91	Process Computer	No	C91-01 Plant Parameter Monitoring
D11	Process Radiation Monitoring	Yes	D11-01 Main Steam Line Radiation Monitoring
		No	D11-02 Filter Performance Radiation Monitoring
		No	D11-03 Primary Containment Fission Product Radiation Monitoring
		No	D11-04 Primary Containment Gamma Radiation Monitoring (Narrow Range)
		No	D11-05 Sump Radiation Monitoring
		Yes	D11-06 Primary Containment Gamma Radiation Monitoring (Wide Range)
		No	D11-07 Off-Gas Radiation Monitoring
		No	D11-08 Liquid Process Radiation Monitoring
		No	D11-09 Main Stack Radiation Monitoring
		No	D11-10 Recombiner Building Radiation Monitoring (Unit 1)
		No	D11-11 Reactor Building Vent Stack Radiation Monitoring
		Yes	D11-12 Reactor Building Ventilation Radiation Monitoring
		Yes	D11-13 MCR Air Intake Radiation Monitoring
		Yes	D11-14 Refueling Floor Ventilation Radiation Monitoring
D21	Area Radiation Monitoring	No	D21-01 Radiation Monitoring and Indication
D31	Counting Room Equipment	No	D31-01 Sample Evaluation
D40	Instrument Calibration and Decon Room	No	D40-01 Instrument Maintenance

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
E11	Residual Heat Removal (RHR)	Yes	E11-01 LPCI
		Yes	E11-02 Containment Sprays
		No	E11-03 Suppression Pool Draining
		Yes	E11-04 RHRSW Vessel/Containment Injection
		Yes	E11-05 Shutdown Cooling
		No	E11-06 Fuel Pool Cooling Assist
		No	E11-07 Reactor Vessel Draining
		Yes	E11-08 Suppression Pool Cooling
		No	E11-09 Steam Condensing[1]
		Yes	E11-10 Alternate Shutdown Cooling
E21	Core Spray System	Yes	E21-01 Core Cooling
		No	E21-02 Primary Containment Flooding
		No	E21-03 Torus Fill
		Yes	E21-04 Alternate Shutdown Cooling
		Yes	E21-05 ECCS Keep Fill
E32	MSIV Leakage Control (Unit 2 only)	No	E32-01 Indirect Radioactive Release Control[1]
E41	High Pressure Coolant Injection (HPCI)	Yes	E41-01 Core Cooling
		No	E41-02 Alternate Boron Injection
		No	E41-03 Alt Press Control/Alt Depress
		No	E41-04 RPV Venting
		No	E41-05 Testing of HPCI Pump
E51	Reactor Core Isolation Coolant (RCIC)	Yes	E51-01 Core Cooling
		No	E51-02 Alt Press Control/Alt Depress
		No	E51-03 Alt. Boron Injection
		No	E51-04 RPV Venting
		No	E51-05 Steam Condensing[1]
		No	E51-06 Testing of RCIC Pump
F11	Fuel Servicing Equipment	No	F11-01 New Fuel Handling/Preparation
F13	Reactor Vessel Servicing Equipment	No	F13-01 Tools for Vessel Disassembly/Reassembly
F14	Reactor In Vessel Servicing Equipment	No	F14-01 Tools for Internal Vessel Disassembly/Reassembly

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
F15	Refueling Equipment	Yes	F15-01 Fuel/Control Rod Handling
F16	Fuel Storage Equipment	No	F16-01 Storage Racks[2]
F17	Under Reactor Vessel Servicing Equipment	No	F17-01 CRD Service
F41	Startrec	No	F41-01 Startup Test Data Acquisition
G11	Radwaste	No	G11-01 Effluent Isolation
		No	G11-02 Liquid Radioactive Waste Processing
		No	G11-03 Solid Radwaste Processing
G13	Heat Trace	Yes	G13-01 Freeze Protection
G31	Reactor Water Cleanup (RWCU)	No	G31-01 Alternate Pressure Control
		No	G31-02 Reactor Water Level Control
		No	G31-03 Coolant Water Chemistry
G41	Spent Fuel Pool Cooling and Clean-up	No	G41-01 Fuel Pool Cooling/Clean-up
G51	Torus Drainage and Purification System	No	G51-01 Torus Water Quality Control/Torus Drainage
G71	Decay Heat Removal	No	G71-01 Fuel Pool and Reactor Cavity Cooling
H11	Main Control Room Panels	Yes	H11-01 Operator Information and Control
H12	Annunciators	No	H12-01 Alarm
H21	In Plant Auxiliary Control Panels	Yes	H21-01 Equipment Support & Integrity
		Yes	H21-02 Operator Information and Control
J11	Fuel	Yes	J11-01 Energy Source
		Yes	J11-02 Spent Fuel Fission Product Barrier
L35	Piping Specialties	Yes	L35-01 Pipe Supports
		Yes	L35-02 Non-Seismic Pipe Supports
		No	L35-03 Miscellaneous Piping and Test Connections
L36	Insulation	No	L36-01 Equipment and Piping Insulation-Inside Drywell
		Yes	L36-02 Piping Insulation-Outside Drywell
L48	Access Doors	Yes	L48-01 Containment Integrity
L51	Instruments	No	L51-01 Seismic Monitoring

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
L52	Loose Parts Monitoring	No	L52-01 RPV Vibration Monitoring (Unit 2 Only)
N11	Main Steam	No	N11-01 Steam Supply Piping
		No	N11-02 Branch Steam Supply Piping
N21	Condensate and Feedwater	No	N21-01 Reactor Coolant Make-up
N22	Auxiliary Drains and Vents	No	N22-01 Condensate Drains
N30	Turbine	No	N30-01 Energy Conversion
		No	N30-02 Pressure Control - Bypass Valves
N32	EHC	No	N32-01 Turbine Control
		Yes	N32-02 Main Turbine Pressure Regulator
N33	Steam Seals	No	N33-01 Sealing Steam to Valves and Turbines
		No	N33-02 Exhaust and Hold-up Volume
N34	Turbine Lube Oil	No	N34-01 Main Turbine Lift Pumps
		No	N34-02 Main Turbine Lube Oil
		No	N34-03 RFP Lube Oil
		No	N34-04 MG Set Lube Oil
		No	N34-05 Main Turbine Turning Gear Lube Oil
N36	Extraction Steam	No	N36-01 Steam Supply to Turbine Building Loads
N38	Main Steam Reheat (MSR)	No	N38-01 Steam Quality
N39	Turning Gear	No	N39-01 Turbine Rotation
N40	Generator	No	N40-01 Power Generation
N41	Generator Core Monitor	No	N41-01 Main Generator Insulation Monitoring
N42	Generator Hydrogen Seal Oil	No	N42-01 Maintain Generator Hydrogen Pressure
N43	Generator Stator Water Cooling	No	N43-01 Stator Cooling
N61	Main Condenser	No	N61-01 Heat Removal
		No	N61-02 Power Generation
		Yes	N61-03 Post Accident Radioactive Decay Holdup

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
N62	Off Gas	No	N62-01 Gaseous Radwaste Effluent Isolation
		No	N62-02 Process & Control The Release of Gaseous Radioactive Wastes
N71	Circulating Water	No	N71-01 Main Condenser Heat Removal
P11	Condensate Transfer & Storage	Yes	P11-01 ECCS/CRD Condensate Supply
		No	P11-02 Condensate Transfer
P21	Demineralized Water	No	P21-01 Demineralized Water Supply to All Plant Loads
P23	Caustic/Acid	No	P23-01 Demin Resin Regeneration (Unit 1 Only)
P25	Amertap	No	P25-01 Condenser Tube Cleaning (Unit 1 Only)
P32	Nitrogen Blanketing	No	P32-01 Corrosion Protection
P33	Sampling System	Yes	P33-01 Display of Hydrogen/Oxygen Information for Operator
		No	P33-02 Post Accident Sampling (PASS)
		No	P33-03 Radwaste Building Process Sampling
		No	P33-04 Reactor Building Process Sampling
		No	P33-05 Turbine Building Process Sampling
		No	P33-06 Drywell Oxygen Content
P41	Plant Service Water	Yes	P41-01 Essential Mechanical/Environmental Support
		Yes	P41-02 Turbine Building Isolation
		No	P41-03 Radwaste Dilution
		No	P41-04 Non-Essential Mechanical/Environmental Support
		Yes	P41-05 1B EDG Cooling (Standby PSW)
		No	P41-06 Circulating Water System Flume Make-up
P42	Reactor Building Closed Cooling Water (RBCCW)	Yes	P42-01 Reactor Building Equipment Cooling
P44	Plant Hot Water Heating	No	P44-01 Reactor Building Climate Control
P50	SCBA Compressor Air	No	P50-01 Compressed Air Supply

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
P51	Station Service Air	No	P51-01 Compressed Air Supply
		No	P51-02 RWCU, FPC & Condensate Demin Low Pressure Air Blowers
P52	Instrument Air	Yes	P52-01 Non-Interruptible Essential Instrument Air Supply
		No	P52-02 Interruptible Essential Instrument Air Supply
P61	Auxiliary Boiler	No	P61-01 Start-up Steam Supply
P62	Environmental Monitoring	No	P62-01 River Influent/Effluent Monitoring
P63	Turbine Building Chillers	No	P63-01 Turbine Building Cooling
P64	Primary Containment Chilled Water (Unit 2)	No	P64-01 Reactor Building/Radwaste Building Cooling
		Yes	P64-02 Drywell Cooling
P65	Reactor Building Chilled Water	No	P65-01 Reactor Building Equipment/Area Cooling
P67	Control Building Chilled Water	No	P67-01 Chilled Water to Control Building HVAC
P70	Drywell Pneumatics	Yes	P70-01 Nitrogen Supply to Drywell Equipment
		No	P70-02 Containment Environment Control
P73	Hydrogen Water Chemistry	No	P73-01 IGSCC Mitigation
P85	Zinc Injection	No	P85-01 Inhibit Radiation Build-up
R13	Isophase Bus	No	R13-01 Bus Duct Cooling
		No	R13-02 Power Transmission
		No	R13-03 Metering & Relaying
R20	Plant A/C Electrical	Yes	R20-01 1E A/C Electrical Supply
		No	R20-02 Station Service A/C Electrical Supply
		No	R20-03 Grounding
R33	Conduits, Raceways & Trays	Yes	R33-01 Wire & Cable Integrity
		Yes	R33-02 Wire & Cable Integrity / Non-Safety Related

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
R42	D/C Electrical	Yes	R42-01 Plant 1E D/C Electrical Supply
		Yes	R42-02 EDG 1E D/C Electrical Supply
		No	R42-03 Cooling Tower D/C Supply
		No	R42-04 Switchyard D/C Supply
		Yes	R42-05 Diesel Fire Pump D/C Supply
		No	R42-06 24/48 D/C Supply
		Yes	R42-07 Appendix "R" Emergency Lights
R43	Emergency Diesel Generators	Yes	R43-01 Stand-by A/C Power Supply
R44	Uninterruptible Power Supply	No	R44-01 Vital A/C
R51	Plant Communications	Yes	R51-01 Personnel Communication
R52	Non Appendix "R" Emergency Lights	No	R52-01 Personnel Access/Egress
S11	Power Transformers	No	S11-01 Power Transmission
		Yes	S11-02 EDG 1B AC Supply
S30	Misc. Equip. & Welding Outlets	No	S30-01 Welding Support
S48	Switchyard Structures	No	S48-01 Power Transmission Equipment Integrity
T23	Primary Containment	Yes	T23-01 Torus/Drywell
T24	Fuel Storage	Yes	T24-01 Spent Fuel Integrity
		Yes	T24-02 New Fuel Integrity
T29	Reactor Building	Yes	T29-01 Containment and Support
T31	Cranes, Hoists & Elevators	No	T31-01 Equipment & Personnel Movement
		Yes	T31-02 Reactor Building Crane
T38	Tornado Vents	Yes	T38-01 Pressure Equalization

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
T41	Reactor Building HVAC	Yes	T41-01 Indirect Radioactive Release Control
		Yes	T41-02 Essential Mechanical/Environ. Support - ECCS Room Coolers
		No	T41-03 Reactor Building/Refueling Floor Environmental Control
		No	T41-04 Miscellaneous Exhaust Fans (Unit 1)
		No	T41-05 Reactor Building Area cooling
		No	T41-06 Temperature Monitoring
		Yes	T41-07 Essential Mechanical/Environ. Support - RCIC and CRD Room Coolers
T45	Equipment and Floor Drainage	No	T45-01 Waste Liquid Collection
		No	T45-02 Primary/Secondary Containment Abnormal Leakage Indication/Isolation
T46	Standby Gas Treatment	Yes	T46-01 Indirect Radioactive Release Control
T47	Drywell Cooling	No	T47-01 Drywell Mechanical/Environmental Support
		No	T47-02 Display of Event Information for Operator

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
T48	Primary Containment Purge & Inerting	Yes	T48-01 Primary Containment Nitrogen Inerting
		No	T48-02 Primary Containment Purge And Vent
		Yes	T48-03 Primary Containment Vacuum Relief
		Yes	T48-04 Containment/Reactor Building Parameter Monitoring
		No	T48-05 ILRT Connection Path
		Yes	T48-06 Drywell Pneumatic Nitrogen Supply
		No	T48-07 TIP System Nitrogen Supply
		No	T48-08 Turbine Building Nitrogen Blanketing Supply
		No	T48-09 Reactor Building Instrument Air Nitrogen Back-up
		No	T48-10 Hydrogen Recombiner Nitrogen Blanketing Supply
T49	Post LOCA Hydrogen Recombiners	Yes	T49-01 Containment Combustible Gas Control (Unit 2 Only)
T51	A/C Lighting	No	T51-01 Personnel Access and Safety
T52	Drywell Penetrations	Yes	T52-01 Primary Containment Integrity
T54	Reactor Building Penetrations	Yes	T54-01 Secondary Containment Integrity
U29	Turbine Building	Yes	U29-01 BOP Equipment Integrity and Support
U31	Cranes, Hoists & Elevators	No	U31-01 Turbine Building Crane[3]
U41	Turbine Building HVAC	No	U41-01 Turbine Building Ventilation
		No	U41-02 Turbine Building Cooling (Area Coolers)
U61	Turbine Building Leak Detection	No	U61-01 Turbine Building Temperature Monitoring
		No	U61-02 Electrical Signal Interlock
V29	Radwaste Building	No	V29-01 Waste Processing Equipment Integrity
V41	Radwaste Building HVAC	No	V41-01 Radwaste Building Environmental Control

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
W21	Circulating Water System Sump Pumps	No	W21-01 Circulating Water Pump Equipment Integrity[4]
W23	Circulating Water Chlorination	No	W23-01 Algae/Barnacle Growth Inhibitor (Unit 1 Only)
W24	Cooling Towers	No	W24-01 Heat Exchanger
W29	Circulating Water Structures	No	W29-01 Circulating Water System Integrity
W33	Traveling Water Screens/Trash Rakes	Yes	W33-01 Intake Structure Trash Removal
		No	W33-02 Screen Wash
		Yes	W33-03 Screen Wash Isolation
W35	Intake Structure	Yes	W35-01 RHRSW and PSW system Integrity
X29	Buildings	No	X29-01 Equipment Integrity & Personnel Habitability
X41	Outside Structure HVAC	Yes	X41-01 Intake Structure Environmental Control
		Yes	X41-02 EDG Building Environmental Control
		Yes	X41-03 EDG Building Battery Room H2 Control
		Yes	X41-04 EDG Switchgear Room Heating and Ventilation
		Yes	X41-05 EDG Building Oil Storage Room Ventilation

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
X42	Potable/Sanitary Water	No	X42-01 Drinking & Sanitary Water
X43	Fire Protection	Yes	X43-01 Cardox Fire Suppression for EDG's
		Yes	X43-02 Halon Fire Suppression for Remote Shutdown Panel (Unit 2)
		No	X43-03 RPV Inventory Makeup
		Yes	X43-04 Plant Wide Fire Suppression With Water
		No	X43-05 Halon Fire Suppression For Miscellaneous Applications
		Yes	X43-06 Fire Detection
		Yes	X43-07 Penseals & Fire Barriers For Preventing Fire Propagation
		Yes	X43-08 Manual CO_2 Fire Protection
		No	X43-09 EDG Building Fire Protection[5]
		Yes	X43-10 Cardox Fire Suppression for the Computer Room
X75	Emergency Response Facilities	Yes	X75-01 Class 1E Signal Isolation
		No	X75-02 Plant Parameter Monitoring (SPDS/ERFDS)
		No	X75-03 Emergency Response Coordination/Support
		No	X75-04 Plant Simulator
Y29	Yard Structures	Yes	Y29-01 Equipment Integrity and Personnel Habitability
Y32	Off-Gas Stack[6]	Yes	Y32-01 Gaseous Effluent Elevated Release
Y33	Meteorological Tower	No	Y33-01 Weather Monitoring
Y34	Security	No	Y34-01 Facility Protection
Y39	EDG Building	Yes	Y39-01 EDG and Equipment Integrity
Y42	Deep Well Pumps	No	Y42-01 Sanitary Water Supply
Y44	Sewage & Sanitary Drains	No	Y44-01 Sewage Treatment
Y47	Microwave	No	Y47-01 Intra Company Communication
Y52	Fuel Oil	Yes	Y52-01 EDG Fuel Oil Supply
		No	Y52-02 Auxiliary Boiler Fuel Oil Supply

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
Z29	Control Building	Yes	Z29-01 Equipment Integrity & Personnel Habitability
Z41	Control Building HVAC	No	Z41-01 LPCI Inverter Room Essential Cooling/Environmental Support[1]
		Yes	Z41-02 Control Room Habitability and Essential Mechanical/Environmental Support.
		Yes	Z41-03 Control Building Environmental Support
Z52	Chemical Lab	No	Z52-01 Perform Lab Tests

Notes:

1. Function no longer exists, but is retained in the listing solely for continuity.
2. F16-01 is retained for continuity purposes. The function is included in T24-02.
3. U31-01 is retained for continuity purposes. The function is included in T31-01.
4. W21-01 is retained for continuity purposes. The function is included in W29-01.
5. X43-09 is retained for continuity purposes. The function is included in X43-01.
6. The elevated release structure is commonly referred to in this application as the main stack.

2.3 MECHANICAL SYSTEMS SCREENING RESULTS

The following system descriptions are included to provide the reader with the following information:

- A general description of the system and its purpose;
- The intended functions associated with the system;
- A list of the various mechanical component groups for the system that are subject to an aging management review.

Note that the intended functions define the boundaries by which various component groups are analyzed for aging management purposes. The system description is informational and is not intended to define boundaries.

2.3.1 REACTOR

2.3.1.1 Reactor Assembly System [B11]

System Description

The reactor vessel has three major purposes:

- Contain core, internals and moderator.
- Serve as a high integrity barrier against leakage.
- Provide a floodable volume.

The reactor assembly consists of the reactor pressure vessel (RPV) and its internal components of the core, shroud, steam separator and dryer assemblies, and jet pumps. Also included in the reactor assembly are the control rods, control rod drive (CRD) housings, and the CRD. The RPV is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction. The major reactor internal components are the core (fuel, channels, control blades, and instrumentation), the core support structure (including the core shroud, shroud head, separators, top guide, and core support), the steam dryer assembly, and the jet pumps. The reactor internal structural elements are stainless steel or other corrosion-resistant alloys.

The reactor vessel is located inside the primary containment building. The internal environment of the RPV is reactor water, normally at 533 °F and 1055 psia during plant operation. Water quality is maintained within the specified limits. During plant conditions that require the operation of the shutdown cooling mode of RHR, reactor water can be cooled to approximately 117 °F via the RHR heat exchangers and recirculated back to the reactor through the residual recirculating system (RRS) piping. During plant shutdown conditions, the water temperature in the RPV can be as low as 70 °F.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

B11-01 – Nuclear Boiler. The reactor vessel internals provide proper coolant distribution to allow power operation without fuel damage and provide positioning and support for fuel assemblies to ensure control rod movement is not impaired. The RPV including the control rods and drives are evaluated as a pressure boundary as part of the nuclear boiler system [B21].

Although the pressure boundary function was scoped as part of function B21-02 in this application, the RPV and control rod drive pressure boundary components are listed in Table 2.3.1-1 for convenience of review.

B11-02 – Reactivity Control. The CRD housing supports mitigate damage to the fuel barrier in the event a drive housing breaks or separates from the bottom of the reactor.

Component Groups Requiring an Aging Management Review

Table 2.3.1-1 Components Supporting Reactor and Internals System [B11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Access Hole Covers*	Pressure Boundary	Nickel Based Alloy
Appurtenances	Pressure Boundary Fission Product Barrier Structural Support	Nickel Based Alloy Stainless Steel
Attachments and Connecting Welds	Pressure Boundary Fission Product Barrier Structural Support	Carbon Steel Low Alloy Steel Nickel Based Alloy Stainless Steel
Closure Studs	Pressure Boundary Fission Product Barrier	Low Alloy Steel
Control Rod Drive	Pressure Boundary Structural Support	Stainless Steel
Core ΔP/SLC Line*	Pressure Boundary	Stainless Steel
Core Spray Internal Piping	Pressure Boundary	Stainless Steel
Core Spray Sparger	Pressure Boundary Flow Distribution	Stainless Steel
Core Support Plate*	Pressure Boundary Structural Support	Stainless Steel
CRD Housing and CR Guide Tubes	Structural Support	Stainless Steel
Dry Tube Weld to Guide Tube	Pressure Boundary	Stainless Steel
Fuel Supports*	Pressure Boundary Structural Support	Cast Austenitic Stainless Steel
Jet Pump Assemblies	Pressure Boundary Structural Support	Stainless Steel Cast Austenitic Stainless Steel
Nozzles	Pressure Boundary Fission Product Barrier Structural Support	Low Alloy Steel
Penetrations	Pressure Boundary Fission Product Barrier Structural Support	Nickel Based Alloy Stainless Steel
Safe Ends	Pressure Boundary Fission Product Barrier Structural Support	Stainless Steel Carbon Steel Low Alloy Steel Nickel Based Alloy
Shell and Closure Heads	Pressure Boundary Fission Product Barrier Structural Support	Low Alloy Steel

Component Groups Requiring an Aging Management Review

Table 2.3.1-1 Components Supporting Reactor and Internals System [B11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Material
Shroud	Pressure Boundary Structural Support	Stainless Steel
Shroud Supports	Pressure Boundary Structural Support	Nickel Based Alloy Low Alloy Steel
Shroud Tie Rods*	Structural Support	Stainless Steel
Thermal Sleeves	Pressure Boundary Fission Product Barrier	Stainless Steel Nickel Based Alloy
Top Guide	Structural Support	Stainless Steel

* No aging effects requiring management

2.3.1.2 Nuclear Boiler System [B21]

System Description

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

The system contains the following major components:

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

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

B21-01 – Pressure Control. The pressure control function of the nuclear boiler system prevents any overpressurization of the nuclear system. It also provides automatic depressurization for small breaks to allow for low pressure coolant injection (LPCI) and core spray (CS) operation. This function is described as the automatic depressurization system (ADS). The low-low set (LLS) function mitigates the thrust loads on the SRV discharge lines and the high-frequency loads on the torus shell from subsequent SRV actuations during small and intermediate-break loss of coolant accidents (LOCAs). The LLS also allows extended time between SRV subsequent actuations to allow the SRV discharge line water leg to return to original level after an actuation.

B21-02 – Reactor Coolant Pressure Boundary Integrity. The nuclear boiler system is designed to maintain the reactor coolant pressure boundary integrity. This function includes pressure containing Class 1 piping and components which form a portion of the reactor coolant pressure boundary with the exceptions of the pressure control and reactor recirculation functions.

For primary containment isolation devices, only the valve body is included in the scope of B21-02. The remainder of the valves (operators, motors, etc.) are included in system C61 (primary containment isolation). Portions of the following pressure containing systems are included in the B21-02 function: B11, B31, C11, C41, E11, E21, E41, E51, G31, L50. The main steam line flow restrictors are also included in this function.

<u>B21-03 – Rod Worth Minimizer.</u> The rod worth minimizer provides a means of enforcing procedural restrictions on preprogrammed control rod manipulations which are designed to limit rod worth to the values assumed in the plant accident analysis (design basis rod drop accident).

<u>B21-04 – Nuclear Boiler Instrumentation.</u> Nuclear boiler instrumentation provides process information to the operator and signals to other systems in the nuclear power plant.

Component Groups Requiring an Aging Management Review

Table 2.3.1-2 Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Crack Growth Monitor (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Flow Restrictor	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping (non-Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping (non-Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping (Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Restricting Orifice (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Thermowell (non-Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Thermowell (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies (non-Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies (non-Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies (Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies (Class 1)	Pressure Boundary Fission Product Barrier	Cast Austenitic Stainless Steel

2.3.1.3 Fuel [J11]

System Description

Nuclear fuel is provided as a high integrity assembly of fissionable material which can be arranged in a critical array. The assembly must be capable of efficiently transferring the generated fission heat to the circulating coolant water, while maintaining structural integrity and keeping the fission products contained.

The external environment of the fuel is a cladding surrounded by water.

The fuel cladding experiences the complete range of reactor coolant pressure and temperatures.

Additional information may be found in Unit 2 FSAR paragraph 4.2.1.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

J11-01 – Energy Source. The nuclear fuel provides a high-integrity assembly of fissionable material capable of efficiently transferring the generated fission heat to the circulating reactor coolant water, while maintaining structural integrity and keeping the fission products contained. The nuclear fuel serves as the initial barrier to release of fission products. The fuel assembly is designed to ensure that fuel damage does not result in the release of radioactive materials in excess of the guideline values of 10 CFR 20.1- 20.601, 50 and 100.

J11-02 – Spent Fuel Fission Product Barrier. The spent fuel fission product barrier provides the barrier to prevent the release of fission products that are retained in the spent fuel. The Zircaloy-2 cladding that covers the spent fuel mitigates the consequences of a fuel handling accident. The cladding ensures that fuel damage does not result in the release of radioactive materials in excess of the guidelines values of 10 CFR 20.1- 20.601, 50 and 100.

Component Groups Requiring an Aging Management Review

None

2.3.2 REACTOR COOLANT SYSTEMS

2.3.2.1 Reactor Recirculation System [B31]

System Description

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

RRS consists of two parallel loops, each consisting of a recirculation pump, suction and discharge block valves, piping, fittings, flow elements and connections supporting flow, and differential pressure instrumentation. The RRS interfaces with the residual heat removal (RHR) and reactor water cleanup (RWCU) systems to provide a flow-path in support of shutdown cooling, low pressure coolant injection (LPCI), RWCU, and reactor water level control functions.

More information about this system may be found in Unit 1 FSAR Section 4.3 and Unit 2 FSAR subsection 5.5.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>B31-02 – Recirculating Pump Trip Breaker Trip.</u> The recirculating pump trip (RPT) breakers are designed to trip the reactor on appropriate signals—high reactor vessel steam dome pressure signal, or an indication of an ATWS-RPT reactor water level. The RPT breakers trip to prevent the core from exceeding thermal limits during abnormal transients. The system function is designed to aid the reactor protection system (RPS) in protecting the integrity of the fuel barrier. This function meets the safe shutdown criteria on the basis that the RPS is necessary to allow the control rods or the standby liquid control (SLC) system to safely and effectively shutdown the reactor.

<u>B31-03 – Reactor Coolant Pressure Boundary.</u> The RRS ensures adequate core cooling during power operation by supplying coolant flow past the reactor fuel bundles. The system consists of two loops external to the RPV. The piping, pumps, and valves that form these loops make up part of the reactor coolant pressure boundary.

This function only includes recirculation piping, pumps, and valves up to the first isolation valves of the small bore branches. Class 1 piping including valves B31-F019/20 will be evaluated as part of B21-02. Valves B31-F031 A/B are required for EQ compliance per the EQ master list.

Component Groups Requiring an Aging Management Review

Table 2.3.2-1 Components Supporting Reactor Recirculation [B31] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting (Class 1)	Fission Product Barrier, Pressure Boundary	Carbon Steel
Flow Nozzle (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel
Piping (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel
Pump Casings and Cover (Class 1)	Fission Product Barrier, Pressure Boundary	Cast Austenitic Stainless Steel
Thermowell (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies (Class 1)	Fission Product Barrier, Pressure Boundary	Cast Austenitic Stainless Steel
Valve Bodies (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel

2.3.3 ENGINEERED SAFETY FEATURES

2.3.3.1 Standby Liquid Control System [C41]

System Description

The standby liquid control system assures reactor shutdown, from full power operation to cold subcritical, by mixing a neutron absorber with the primary reactor coolant. The system is designed for the condition when an insufficient number of control rods can be inserted from the full power setting. The neutron absorber is injected within the core zone in sufficient quantity to provide a sufficient margin for leakage or imperfect mixing. The system is not a scram or a backup scram system for the reactor; it is an independent backup system for the control rod drive (CRD) system.

The standby liquid control system is located in the reactor building and consists of a low temperature sodium pentaborate solution storage tank, a test tank, a pair of full capacity positive displacement pumps, two explosive actuated shear plug valves, two accumulators, the poison sparger, and the necessary piping, valves, and instrumentation. The standby liquid control system is manually initiated from the control room by use of a three-position key-lock switch.

More information can be found on this system in Unit 2 FSAR subsection 4.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C41-01 – Reactivity Control. The standby liquid control system assures reactor shutdown from full power operation to cold subcritical by mixing a neutron absorber with the primary reactor coolant.

C41-03 – SLC Testing. The testing function is not safety related. However, to accomplish this function, equipment from the C41-01 function is used as well as the test tank and piping. The equipment common to C41-01 is brought in scope under that function. The test tank is qualified to seismic category II/I criteria and, therefore, has the potential to prevent a safety-related function. It is for that reason that this function is conservatively brought into scope.

Component Groups Requiring an Aging Management Review

Table 2.3.3-1 Components Supporting Standby Liquid Control [C41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Stainless Steel
Pump Accumulators	Pressure Boundary	Carbon Steel
Pump Casings	Pressure Boundary	Stainless Steel
Tanks	Pressure Boundary	Stainless Steel
Temperature Element	Pressure Boundary	Stainless Steel
Temperature Switch	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.3.2 Residual Heat Removal System [E11]

System Description

The residual heat removal (RHR) system is composed of several components and subsystems which are required to:

- Restore and maintain reactor vessel water level after a loss of coolant accident (LOCA);
- Limit temperature and pressure inside the containment after a LOCA;
- Remove heat from the suppression pool water; and
- Remove decay and residual heat from the reactor core to achieve and maintain a cold shutdown condition.

Note that the RHR service water functions are included in E11.

The RHR system consists of four pumps and two heat exchangers divided into two loops of two pumps and one heat exchanger each, plus the associated instruments, valves, and piping. The RHR pumps take suction from the suppression pool or the reactor coolant recirculation loop. The pumps discharge into the recirculation loop, the suppression pool, the containment spray headers, the spent-fuel pool cooling and cleanup system, depending upon the desired mode of system operation. The RHR system interfaces with the recirculation system to provide a flow-path in support of shutdown cooling and low pressure coolant injection (LPCI). The RHR system is part of the reactor coolant pressure boundary; therefore, it also maintains the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

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

More information about the RHR system may be found in Unit 1 FSAR Section 4.8 and Unit 2 FSAR subsection 5.5.7.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

E11-01 – Low pressure Coolant Injection (LPCI). The LPCI restores and maintains the coolant inventory in the reactor vessel so the core is adequately cooled following a design basis LOCA and other design basis events.

E11-02 – Containment Spray. Containment spray provides post-accident containment atmosphere temperature and pressure control by use of spray nozzles located in both the drywell and the torus area.

E11-04 – RHRSW Vessel/Containment Injection. RHRSW provides a reliable supply of cooling water to the reactor pressure vessel (RPV) following a loss of RHR/core spray or to flood the primary containment to provide cooling to the exterior of the reactor vessel using raw river water.

E11-05 – Shutdown Cooling. Shutdown cooling removes decay and residual heat from the reactor during shutdown and cooldown when the reactor pressure is so low that the vacuum in the condenser cannot be maintained, rendering the condenser inoperable or the high pressure coolant injection (HPCI) and/or reactor core isolation cooling (RCIC) pumps inoperable due to a lack of steam.

E11-08 – Suppression Pool Cooling. Suppression pool cooling limits the water temperature in the suppression pool to ensure it has adequate heat capacity remaining in the event of a design basis LOCA, and removes heat post-accident and during testing of the HPCI and RCIC systems.

E11-10 – Alternate Shutdown Cooling. Alternate shutdown cooling provides an alternate means to cool and depressurize the reactor vessel following a fire or other transient which leads to a loss of shutdown cooling.

Component Groups Requiring an Aging Management Review

Table 2.3.3-2 Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Conductivity Element	Fission Product Barrier, Pressure Boundary	Stainless Steel
Heat Exchanger Channel Assembly	Pressure Boundary	Carbon Steel
Heat Exchanger Impingement Plate	Shelter/ Protection	Stainless Steel
Heat Exchanger- Shell	Fission Product Barrier, Pressure Boundary	Carbon Steel
Heat Exchanger Tube Sheet	Fission Product Barrier Pressure Boundary	Carbon Steel Stainless Steel
Heat Exchanger Tubes	Fission Product Barrier, Pressure Boundary	Stainless Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Pump Casings	Fission Product Barrier, Pressure Boundary	Carbon Steel
Pump Casings - Bowl Assembly	Pressure Boundary	Cast Austenitic Stainless Steel
Pump Discharge Head	Pressure Boundary	Carbon Steel
Pump Sub Base	Structural Support	Carbon Steel
Restricting Orifices	Fission Product Barrier, Pressure Boundary, Flow Restriction	Stainless Steel
Strainer Bodies	Debris Protection	Carbon Steel
Strainers	Debris Protection	Stainless Steel
Thermowell	Fission Product Barrier, Pressure Boundary	Carbon Steel
Tubing	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Carbon Steel

2.3.3.3 Core Spray System [E21]

System Description

The core spray (CS) system is one of the emergency core cooling systems (ECCSs) which protects the core from overheating in the event of a loss of coolant accident (LOCA). The CS system is a low pressure system. Actuation of the CS system results from low reactor vessel water level (level 1) or high drywell pressure or manual action. Injection valves to the reactor require a signal from the reactor low pressure permissive switches before opening to provide over-pressure protection to the system. The pumps take suction from the suppression pool and spray on the top of fuel assemblies to cool the core and limit the fuel cladding temperature. An alternate suction source for the CS system, the condensate storage tank (CST), is used primarily for providing reactor pressure vessel (RPV) makeup and an injection test supply during outages, and would not normally be used post accident. The CS system works in conjunction with low pressure coolant injection (LPCI).

The CS system has two independent loops. Each loop includes a 100% capacity centrifugal pump driven by an electric motor, a sparger ring in the reactor vessel above the core, piping, valves, and associated controls and instrumentation. To enable the CS system to make a quick startup and to minimize the water hammer possibilities during startup, the CS system discharge lines are always maintained full of water by the jockey pump system. The jockey pump system consists of two centrifugal pumps in each of the two loops. The suction and discharge lines of these pumps are connected through piping and valves to the suction and discharge lines of the CS pumps respectively. Continuous operation of the jockey pumps ensures the ECCS's discharge lines remain full. The jockey pump system also provides the same feature for the residual heat removal (RHR) system.

The CS system is described in Unit 1 FSAR subsection 6.4.3 and Unit 2 FSAR paragraph 6.3.2.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

E21-01 – Core Cooling. The CS system protects the core by removing decay heat following a postulated design basis LOCA or other design basis event.

E21-04 – Alternate Shutdown Cooling. The CS system provides an alternate means to cool and depressurize the reactor vessel following a fire.

E21-05 – Emergency Core Cooling System Keep Fill. The jockey pumps of the Core Spray System are provided to keep the core spray and low pressure coolant injection lines full of water, thus minimizing the delay time for emergency core cooling and the possibility of water hammer. This function is brought into scope solely as a pressure boundary.

Component Groups Requiring an Aging Management Review

Table 2.3.3-3 Components Supporting Core Spray System [E21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Pump Casings	Fission Product Barrier, Pressure Boundary	Carbon Steel
Restricting Orifice	Fission Product Barrier, Pressure Boundary, Flow Restriction	Stainless Steel
Strainers	Debris Protection	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Carbon Steel

2.3.3.4 High Pressure Coolant Injection System [E41]

System Description

The high pressure coolant injection (HPCI) system supplies makeup coolant into the reactor vessel from a fully pressurized to a preset depressurized condition. Demineralized makeup water is supplied from the condensate storage tank (CST) or treated water from the suppression pool. The flow rate of the system will maintain the reactor vessel coolant inventory until the reactor pressure drops sufficiently to permit the low pressure core cooling systems to automatically inject coolant into the vessel.

The HPCI system consists of a turbine driven pump train, piping, valves, and controls that provide a complete and independent emergency core cooling system (ECCS). A test line permits functional testing of the system during normal plant operation. A minimum flow bypass line bypasses pump discharge flow to the suppression pool to protect the pump in the event of a stoppage in the main discharge line. Reactor vessel steam is supplied to the turbine. Turbine exhaust steam is then dumped to the suppression pool.

The HPCI system is further described in the Unit 1 FSAR subsection 6.4.1 and Unit 2 FSAR paragraph 6.3.2.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

E41-01 – Core Cooling. The HPCI system assures the reactor is adequately cooled to limit fuel-clad temperature in the event of a small break in the reactor coolant system and a loss of coolant which does not result in rapid depressurization of the reactor vessel. This function permits shutdown of the plant while maintaining sufficient reactor vessel water inventory until the reactor is depressurized.

Component Groups Requiring an Aging Management Review

Table 2.3.3-4 Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Bolting	Pressure Boundary Fission Product Barrier	Stainless Steel
Flexible Connectors	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Stainless Steel
Pump Baseplate	Structural Support	Carbon Steel
Pump Casings	Pressure Boundary Fission Product Barrier	Carbon Steel
Restricting Orifice	Pressure Boundary Flow Restriction Fission Product Barrier	Stainless Steel
Suction Strainer	Debris Protection	Stainless Steel
Thermowell	Pressure Boundary	Stainless Steel
Turbine	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Stainless Steel

2.3.3.5 Reactor Core Isolation Cooling System (RCIC) [E51]

System Description

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

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

The system is described in the Unit 1 FSAR, Section 4.7 and Unit 2 FSAR subsection 5.5.6.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

E51-01 – Core Cooling. The RCIC system provides a high pressure makeup coolant system which supports the reactor shutdown when the feedwater system is unavailable.

Component Groups Requiring an Aging Management Review

Table 2.3.3-5 Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Bolting	Pressure Boundary Fission Product Barrier	Stainless Steel
Flexible Connector	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Stainless Steel
Pump Baseplate	Structural Support	Carbon Steel
Pump Casing	Pressure Boundary Fission Product Barrier	Carbon Steel
Restricting Orifices	Pressure Boundary, Flow Restriction Fission Product Barrier	Stainless Steel
Steam Trap	Pressure Boundary Fission Product Barrier	Stainless Steel
Steam Trap	Pressure Boundary Fission Product Barrier	Carbon Steel
Strainer- Steam Exhaust	Pressure Boundary Fission Product Barrier	Carbon Steel
Suction Strainer	Debris Protection	Stainless Steel
Thermowell	Pressure Boundary Fission Product Barrier	Carbon Steel
Thermowell	Pressure Boundary Fission Product Barrier	Stainless Steel
Turbine	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Cast Austenitic Stainless Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Stainless Steel

2.3.3.6 Standby Gas Treatment System [T46]

System Description

The standby gas treatment system (SGTS) is an engineered safety feature (ESF) system for ventilation and cleanup of the primary and secondary containment during certain postulated design basis accidents (DBAs), and meets the design, quality assurance, redundancy, energy source, and instrumentation requirements for ESF systems. The SGTS is also used as a normal means of venting the drywell.

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

Additional information may be found for this system in Unit 1 FSAR paragraph 5.3.3.3 and Unit 2 FSAR subsection 6.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T46-01 – Indirect Radioactive Release Control. The SGTS is designed to minimize the release of radioactive materials to the environment during accident conditions. The SGTS is the ESF system for ventilation and cleanup of the primary and secondary containment during certain postulated DBAs.

Component Groups Requiring an Aging Management Review

Table 2.3.3-6 Components Supporting Standby Gas Treatment System [T46] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Filter Housing	Fission Product Barrier, Pressure Boundary	Galvanized Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Piping	Fission Product Barrier, Pressure Boundary	Stainless Steel
Piping	Fission Product Barrier, Pressure Boundary	Copper
Piping	Fission Product Barrier, Pressure Boundary	Galvanized Steel
Rupture Disc	Fission Product Barrier, Pressure Boundary	Stainless Steel
Thermowell	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Gray Cast Iron
Valve Bodies	Fission Product Barrier, Pressure Boundary	Carbon Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Copper Alloy

2.3.3.7 Primary Containment Purge And Inerting System [T48]

System Description

The primary containment purge and inerting system primarily provides and maintains an inert atmosphere in the primary containment for combustible gas control and fire protection. Plant Technical Specifications require that within 24 hours of reactor operation, the inerting system injects a sufficient amount of gaseous nitrogen into the drywell and torus so that the oxygen concentration falls below 4% by volume.

Major equipment for the purge and inerting system includes a purge air supply fan, liquid nitrogen storage tank, ambient vaporizer, steam vaporizer, vacuum breaker, valves, piping, controls, and instrumentation. The purge and inerting system provides containment vent paths to the standby gas treatment system which provides a vent path to the main stack for containment vent and purge operations.

More information may be found in Unit 1 FSAR paragraph 5.2.3.8 and 9 and Unit 2 FSAR Section 6.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>T48-01 – Primary Containment Nitrogen Inerting.</u> The purge and inerting system provides and maintains an inerted atmosphere in the primary containment for combustible gas control and fire protection purposes.

<u>T48-03 – Primary Containment Vacuum Relief.</u> The primary containment relief valves are designed to maintain an external pressure of not more than 2 psi greater than the concurrent internal pressure. It is to prevent a collapse in either the drywell or torus as a result of the most rapid cooldown transient that can occur during operation or a postulated accident condition assuming the failure of a single active component.

<u>T48-04 – Containment/ Reactor Building Parameter Monitoring.</u> The containment/reactor building parameter monitoring function monitors and records drywell and torus safety parameters in the main control room. The parameters monitored include torus air and water temperature, water level, pressure and drywell pressure and temperature.

<u>T48-06 – Drywell Pneumatic Nitrogen Supply.</u> The purge and inerting system provides a safety grade back-up supply of nitrogen gas for the drywell pneumatic system. The nitrogen gas provides motive force to the nuclear boiler system safety relief valves, main steam isolation valves, and various other safety-related valves in the event of a loss of normal drywell pneumatic supply.

Component Groups Requiring an Aging Management Review

Table 2.3.3-7 Components Supporting Primary Containment Purge and Inerting System [T48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Flex Hose	Pressure Boundary Fission Product Barrier	Stainless Steel
Nitrogen Tank Jacket	Structural Support	Carbon Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Pressure Buildup Coil	Pressure Boundary Exchange Heat	Stainless Steel
Rupture Disc	Pressure Boundary	Stainless Steel
Storage Tank	Pressure Boundary	Stainless Steel
Thermowell	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel
Vaporizer	Pressure Boundary Exchange Heat	Stainless Steel

2.3.3.8 Post LOCA Hydrogen Recombiners System [T49] (Unit 2 only)

System Description

The post loss of coolant accident (LOCA) hydrogen recombiner system ensures that hydrogen does not accumulate within the primary containment in combustible concentrations following a LOCA. This is accomplished by drawing primary containment atmosphere from the drywell and passing it through the recombiner where the hydrogen reacts with available oxygen to form water vapor. The recombiner discharge is to the suppression pool (torus).

The hydrogen recombiner system is part of the combustible gas control system and consists of two independent 100% capacity identical trains. Each train consists of three packages: the recombiner skid, the control console, and the power panel. The recombiner skid consists of inlet piping, flowmeters, flow control valve, an enclosed blower assembly, heater section, reaction chamber, direct contact water spray connected to the power panel, and the control console through instrument and power cables. Coolant for the water spray gas cooler is provided by the residual heat removal (RHR) system.

More information can be found about this system in Unit 2 FSAR subsection 6.2.5.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T49-01 – Containment Combustible Gas Control. The post LOCA hydrogen recombiner system ensures that hydrogen does not accumulate within the primary containment in combustible concentrations following a LOCA.

Component Groups Requiring an Aging Management Review

Table 2.3.3-8 Components Supporting Post LOCA Hydrogen Recombiner System [T49] Intended Functions and Their Component Functions (Unit 2 only)

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Stainless Steel

2.3.4 AUXILIARY

2.3.4.1 Control Rod Drive (CRD) System [C11]

System Description

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

The alternate rod insertion system is a subsystem of the CRD system. It is a backup means of scramming the reactor by venting the scram air header. It is completely independent of the reactor protection system (RPS) and was installed for the purpose of reducing the probability of an anticipated transient without scram (ATWS) event.

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

More information about this system may be found in Unit 2 FSAR subsections 4.1.3 and 4.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C11-04 – Reactor Scram. The scram mode allows quick shutdown of the reactor by rapidly inserting withdrawn control rods into the core in response to a manual or automatic signal.

C11-07 – Alternate Rod Insertion. Alternate rod insertion reduces the probability of the occurrence of an scram event. Signals are provided which respond to an ATWS event or to a manual initiation to depressurize the CRD scram pilot valve air header using valves that are different from the RPS scram valves, thus providing a parallel path for control rod insertion.

Component Groups Requiring an Aging Management Review

Table 2.3.4-1 Components Supporting Control Rod Drive System [C11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Accumulator	Fission Product Barrier, Pressure Boundary	Carbon Steel
Bolting	Fission Product Barrier, Pressure Boundary	Carbon Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Piping	Fission Product Barrier, Pressure Boundary	Stainless Steel
Rupture Disc	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Carbon Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Copper Alloy
Valve Bodies	Fission Product Barrier, Pressure Boundary	Stainless Steel

2.3.4.2 Refueling Equipment System [F15]

System Description

The refueling platform equipment assembly is used for handling and transporting reactor core internals and service and handling equipment associated with the refueling operation. The refueling platform equipment assembly consists of the refueling platform, fuel grapple, grapple headlight, and the hardware required to assemble these components into a workable unit.

The refueling platform is a bridge structure that spans the refueling pool and the reactor well and travels on rails which extend the length of the fuel storage pool and the reactor well. A working platform extends the width of the bridge structure, providing working access to the entire width of the pools and reactor well area. The combination of the bridge movement for the length of the pool and the trolley movement for the width of the pool provides complete access to the open pool and reactor well. The movements of the bridge and trolley are displayed so that positions above known locations, such as the location of in-core fuel assemblies, can be repeatedly reproduced from dials on the trolley cab.

The fuel grapple extends downward, below the underside of the refueling platform, into the pool or reactor well. The telescoping grapple is extended or lowered by a fuel hoist. The position of the air-operated grapple is indicated in the control station.

More information on refueling may be found in Unit 1 FSAR Section 7.6 and Unit 2 FSAR Section 9.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

F15-01 – Fuel/Control Rod Handling. The fuel/control rod handling function supports fuel movement and control rod change out and includes the refueling bridge, grapple, hoists, spent fuel servicing equipment, tools, and refueling interlocks.

The structural integrity of the refueling platform is the passive portion of the assembly that is within scope of the License Renewal.

Component Groups Requiring an Aging Management Review

Table 2.3.4-2 Components Supporting Refueling Platform Equipment Assembly [F15] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Anchors and Bolts	Structural Support Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Structural Support Nonsafety Related Structural Support	Carbon Steel
Rivets*	Structural Support	Aluminum
Structural Steel	Structural Support	Carbon Steel

* No aging effects requiring management

2.3.4.3 Insulation System [L36]

System Description

The purpose of insulation is to help retain heat in the process piping and equipment, to prevent moisture from condensing on cold surfaces, to protect equipment and personnel from high temperatures, to prevent piping from freezing in cold areas of the plant, and to protect heat tracing from damage.

Insulation is required in conjunction with heat tracing. Insulation is also credited in heat load calculations for safety related rooms. Failure of this insulation could allow the heat load of the room to exceed the capability of the HVAC system, thus exceeding the design temperature of the room.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

L36-02 – Piping Insulation – Outside Drywell. Insulation is provided in various locations outside the drywell to help retain heat in the process piping and equipment, to prevent moisture from condensing on cold surfaces, to protect equipment and personnel from high temperatures, to prevent piping from freezing in cold areas of the plant, and to protect heat tracing from damage. Examples of inscope piping systems that are heat traced with insulation are plant service water and fire protection. Insulation is also credited in heat load calculations for safety-related rooms. Heat tracing with insulation is required for the standby liquid control system to operate in order to meet ATWS requirements.

Component Groups Requiring an Aging Management Review

Table 2.3.4-3 Components Supporting Insulation [L36] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Aluminum Jacket	Environmental Control	Aluminum
Insulation	Environmental Control	Asbestos Ceramic Calcium Silicate Fiberglass Mineral Fiber
Insulation Bolting	Environmental Control	Galvanized Steel
Insulation Bolting	Environmental Control	Stainless Steel
Stainless Steel Jacket	Environmental Control	Stainless Steel
Wire for Insulation	Environmental Control	Carbon Steel

2.3.4.4 Access Doors System [L48]

System Description

The purpose of the secondary containment access doors is to provide access for personnel and equipment. The secondary containment provides, in conjunction with the primary containment and other engineering safeguards, the capability to limit the release to the environs of radioactive materials so that offsite dose from a postulated design basis accident will be below the guideline values of 10 CFR 100.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

L48-01 – Containment Integrity. Only the doors necessary to maintain secondary containment are included in this function. Secondary containment plays a role in preventing offsite releases. Secondary containment doors have a passive function to maintain structural integrity to preserve secondary containment.

Component Groups Requiring Aging Management Review

Table 2.3.4-4 Components Supporting Access Doors [L48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Structural Steel	Missile Barrier Fission Product Barrier	Carbon Steel

2.3.4.5 Condensate Transfer & Storage System [P11]

System Description

The condensate transfer and storage system provides the plant system makeup, receives reject flow, and provides condensate for any continuous service needs and intermittent batch-type services. The total stored design quantity is based on the demand requirements during refueling for filling the dryer separator pool and the reactor well.

A 500,000 gallon condensate storage tank (CST) supplies the various unit requirements. The unit 1 tank is constructed of aluminum and the unit 2 tank of stainless steel. The system also consists of two condensate transfer pumps and associated piping and valves. The CST provides the preferred supply to the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems. All other suctions are located above suction lines for these systems to provide a 100,000 gallon reserve.

The condensate transfer and storage system is described in Unit 1 FSAR Section 11.9 and Unit 2 FSAR subsection 9.2.6.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P11-01 – ECCS/CRD Condensate Supply. While the CST is nonsafety related, the preferred water source for the RCIC and HPCI systems is the CST. The design of the tank ensures 100,000 gallons of water are set aside for this supply. The HPCI and RCIC systems rely upon this volume of water during the response to station blackout.

Component Groups Requiring an Aging Management Review

Table 2.3.4-5 Components Supporting Condensate Transfer and Storage System [P11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Stainless Steel
Tanks	Pressure Boundary	Aluminum
Tanks	Pressure Boundary	Galvanized Steel
Tanks	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.6 Sampling System [P33]

System Description

The purpose of the primary containment hydrogen and oxygen analyzing system is to provide a means of monitoring hydrogen and oxygen in the primary containment (drywell and torus).

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

Additional information may be found in Unit 2 FSAR paragraph 6.2.4.3.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>P33-01 – Display of Hydrogen/Oxygen Information.</u> The hydrogen-oxygen analyzer system continually measures the hydrogen and oxygen concentrations in the primary containment atmosphere following a loss of coolant accident (LOCA). This information is recorded in the main control room (MCR), and hydrogen concentrations in the drywell above a predetermined level are annunciated. The system is treated as safety related due to Regulatory Guide 1.97 requirements and is included in the EQ program.

Component Groups Requiring an Aging Management Review

Table 2.3.4-6 Components Supporting Sampling System [P33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Piping	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Stainless Steel

2.3.4.7 Plant Service Water System [P41]

System Description

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

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

The PSW system is described in the Unit 1 FSAR Section 10.7 and Unit 2 FSAR subsection 9.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P41-01 – Essential Mechanical/ Environmental Support. The PSW system removes heat generated by various safety-related plant systems, including the reactor building, emergency diesel generators (EDGs), control building, and refueling floor PSW supply.

P41-02 – Turbine Building Isolation. This function closes the 1P41-F310 and 2P41-F316 valves to isolate non-essential loads during emergency conditions to ensure adequate cooling to the diesels and other safety-related loads. This function includes only the isolation valves and associated equipment.

P41-05 – 1B Emergency Diesel Generator Cooling. Diesel Generator 1B is normally supplied by standby plant service water pump 2P41-C002, but during an emergency, generator 1B can be supplied from Unit 1 service water.

Component Groups Requiring an Aging Management Review

Table 2.3.4-7 Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Flexible Connector	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Pump Bowl Assembly	Pressure Boundary	Cast Austenitic Stainless Steel
Pump Discharge Column	Pressure Boundary	Carbon Steel
Pump Discharge Head	Pressure Boundary	Carbon Steel
Pump Sub Base	Structural Support	Carbon Steel
Restricting Orifices	Pressure Boundary Flow Restriction	Stainless Steel
Sight Glass Body	Pressure Boundary	Carbon Steel
Sight Glass Body	Pressure Boundary	Stainless Steel
Sight Glasses*	Pressure Boundary	Ceramic
Strainer	Pressure Boundary	Carbon Steel
Strainer	Pressure Boundary	Gray Cast Iron
Strainer Basket	Debris Protection	Gray Cast iron
Strainer Basket	Debris Protection	Stainless Steel
Thermowells	Pressure Boundary	Carbon Steel
Thermowells	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel
Venturi	Pressure Boundary	Carbon Steel

* No aging effects requiring management

2.3.4.8 Reactor Building Closed Cooling Water System [P42]

System Description

The purpose of the reactor building closed cooling water (RBCCW) system is to provide cooling water to certain auxiliary equipment located in the reactor building.

The RBCCW system is a closed-loop cooling system consisting of three one-half capacity pumps, two full-capacity heat exchangers, a surge tank, and a chemical addition system. The cooling water is conveyed by the pumps to the various system coolers and returned to the pumps by way of the RBCCW heat exchanger. Two of the RBCCW pumps are normally operating with the third pump on standby. The system is started manually. The standby pump, when needed, starts automatically. The heat rejected by the RBCCW system to the heat exchanger is removed by the plant service water (PSW) system.

The RBCCW system is described in the Unit 1 FSAR Section 10.5 and Unit 2 FSAR subsection 9.2.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P42-01 – Reactor Building Equipment Cooling. The RBCCW system cools auxiliary plant equipment located in the reactor building and serves as a closed-cycle barrier between potentially radioactive systems and the plant service water systems. The RBCCW also utilizes demineralized water to substantially reduce the erosion and corrosion of the cooled components.

The RBCCW system is only in the scope of License Renewal to the extent that it provides containment integrity. Specifically, the inscope components function to maintain primary containment via a closed loop inside containment.

Component Groups Requiring an Aging Management Review

Table 2.3.4-8 Components Supporting Reactor Building Closed Cooling Water System [P42] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Flexible Connectors	Pressure Boundary	Stainless Steel
Flow Element	Pressure Boundary	Stainless Steel
Heat Exchanger Shells	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Copper Alloy
Piping	Pressure Boundary	Stainless Steel
Relief Valve Base	Pressure Boundary	Copper Alloy
Temperature Probe	Pressure Boundary	Copper Alloy
Thermowell	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.9 Instrument Air System [P52]

System Description

The purpose of the instrument air system is to provide dried and filtered air to all of the air operated instruments and valves throughout the entire plant (with the exception of equipment inside the drywell).

The instrument air system is divided into the following two subsystems:

- Noninterruptible system provides instrument air for the operation of certain emergency system components.
- Interruptible system provides instrument air to all other components not supplied by the noninterruptible system.

The drywell pneumatic system supplies the motive gas for components within the drywell.

The requirements for the remainder of the compressed air systems are supplied by three oil-free screw-type compressors. Two of these air compressors have a capacity of 500 std ft^3/min and one has a capacity of 700 std ft^3/min. During normal operation, the 700 std ft^3/min compressor supplies all instrument air and high pressure service air requirements outside of the drywell with one of the two 500 std ft^3/min compressors on automatic standby and the other (which requires operator action for start) in the backup mode. Each compressor discharges into an air receiver which in turn discharges into a common manifold that feeds the instrument and service air systems.

Additional information may be found in Unit 1 FSAR Section 10.11 and Unit 2 FSAR subsection 9.3.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P52-01 – Noninterruptible Essential Instrument Air Supply. The noninterruptible essential instrument air supply includes the instrument air system downstream of the noninterruptible essential instrument air check valves and includes the nitrogen backup supply valves. The P52 system is fed from the P51 air compressors under normal operating conditions and has a nonredundant backup of the safety-related nitrogen distribution system. The noninterruptible portion of the instrument air system services certain valves in emergency systems for which operation is desirable, though not essential, following loss of pressure in the service air or interruptible portion of the instrument air system.

Component Groups Requiring an Aging Management Review

Table 2.3.4-9 Components Supporting Instrument Air System [P52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Air Receiver	Pressure Boundary	Stainless Steel
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Hose	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Regulator-Pressure	Pressure Boundary	Carbon Steel
Tubing	Pressure Boundary	Copper
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Copper Alloy

2.3.4.10 Primary Containment Chilled Water System [P64] (Unit 2 Only)

System Description

The primary containment chilled water system is designed to maintain the drywell area below a maximum volumetric average temperature of 150 °F dry bulb during normal operation by providing chilled water to the drywell fan coil units. The primary containment chilled water system consists of two chilled water recirculation pumps, two centrifugal chillers, a chemical addition tank, a chemical feed pump, and an expansion tank. Each chiller consists of a refrigerant compressor, condenser, cooler, accessories, and controls. Each chilled water recirculation pump circulates chilled water through the respective chiller to the fan coil units. Service water from the reactor building service water system is circulated through the chiller condensers for cooling. Demineralized water provides a source of makeup water for the chilled water system. The expansion tank, chemical addition tank, and associated makeup water supply are shared with the reactor and radwaste building chilled water system.

More information may be found in Unit 2 FSAR subsection 9.4.6.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P64-02 – Drywell Cooling. This function is designed to support the drywell cooling system in an effort to maintain the drywell area below a maximum volumetric average temperature of 150 °F dry bulb during normal operations.

The only safety-related function provided during this mode is containment integrity. Specifically, the inscope components function to maintain primary containment integrity via a closed loop inside containment. The controls and instrumentation associated with primary containment isolation for this system function are evaluated as part of C61.

Component Groups Requiring an Aging Management Review

Table 2.3.4-10 Components Supporting Primary Containment Chilled Water System [P64] Intended Functions and Their Component Functions (Unit 2 Only)

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Cap	Pressure Boundary	Copper Alloy
Piping	Pressure Boundary	Carbon Steel
Thermowell	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel

2.3.4.11 Drywell Pneumatics System [P70]

System Description

The drywell pneumatic system supplies motive gas to the following equipment inside the drywell: reactor recirculation system sample line isolation valve, reactor pressure vessel (RPV) head vent valve, core spray (CS) system injection testable check valves and bypass valves, primary containment chilled water system control valves, residual heat removal (RHR) system low pressure coolant injection (LPCI) check valves and bypass valves, and nuclear boiler system safety relief valves (SRVs), and main steam isolation valves (MSIVs).

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

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

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

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>P70-01 – Nitrogen Supply to Drywell Equipment.</u> The nitrogen supply to the drywell equipment provides the motive gas to various equipment. The nitrogen inerting system (T48) supplies the motive gas to the drywell equipment in the drywell during normal operation. After an accident, the motive gas to drywell equipment can be provided from either the drywell pneumatic nuclear boiler system (B21) accumulator, the nitrogen inerting system, or one of the two nitrogen hookup stations.

Component Groups Requiring an Aging Management Review

Table 2.3.4-11 Components Supporting Drywell Pneumatics System [P70] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Filter Housings	Pressure Boundary	Carbon Steel
Filter Housings	Pressure Boundary	Stainless Steel
Flanges	Pressure Boundary	Carbon Steel
Flexible Hoses	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Tubing	Pressure Boundary	Copper
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.12 Emergency Diesel Generators System [R43]

System Description

The purpose of the diesel generators is to provide emergency backup power to 4160 VAC emergency buses E, F, and G in the event of a loss of loss of offsite power. The diesel generators are designed to reach rated speed and voltage within 12 seconds after receiving a start signal. This allows operation of emergency equipment powered from these buses to perform their required function to safely shutdown the plant within the required time.

The emergency diesel generator (EDG) provides a highly reliable source of standby, onsite, ac power. There are five diesel generators supplying standby power to 4.16 kV essential buses: 1E, 1F, 1G of Unit 1; and 2E, 2F, and 2G of Unit 2. Diesel generators 2A and 2C supply buses 2E and 2G respectively. Diesel generator 1B is shared between Units 1 and 2 and can supply power to either 1F or 2F. Diesel generator 1B has a selector switch with “Unit 1 control” and “Unit 2 control” positions, depending on whether it is supplying bus 1F or 2F. Diesel generators 1A and 1C supply buses 1E and 1G, respectively.

The generator field is supplied dc power by a static exciter. The exciter-regulator provides a controlled current to the generator field winding to maintain and control the generator output voltage.

In the automatic mode of voltage control, the generator output voltage is compared to a reference voltage to produce an error signal. Current transformers measure generator load and produce a proportional output. The load signal and voltage error signal are vectorally summed to produce an output which determines the generator field current and, thereby, the generator output voltage.

In the manual mode, the operator controls generator output voltage by adjusting the voltage control lever on the remote control panel. When the voltage balance relay is energized, the output voltage control is transferred from automatic to manual.

Additional information may be found in Unit 1 FSAR Section 8.4 and Unit 2 FSAR Section 8.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R43-01 – Standby AC Power Supply. The standby ac power supply provides ac power in the event of a loss of offsite power. The emergency diesel generator load sequencers are included in this function.

Component Groups Requiring an Aging Management Review

Table 2.3.4-12 Components Supporting Emergency Diesel Generator System [R43] Intended Functions and Their Component Functions

Component	Component Functions	Material
Expansion Tank	Pressure Boundary	Carbon Steel
Filter housing	Pressure Boundary	Carbon Steel
Flex Hose	Pressure Boundary	Stainless Steel
Flexible Connector	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Galvanized Steel
Piping	Pressure Boundary	Stainless Steel
Restricting Orifice	Pressure Boundary	Stainless Steel
Tanks	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.13 Cranes, Hoists and Elevators System [T31]

System Description

The reactor building crane is the only inscope component for this system. The purpose of the reactor building crane is to provide the capability for moving major components for refueling operations and maintenance.

The Unit 1 reactor building crane provides service to both Unit 1 and Unit 2. It has the capability to move loads up to 125 tons with the main hook. This capability includes the handling of shield plugs, reactor vessel heads, drywell heads, steam dryers, steam separators, and the spent-fuel shipping cask. The reactor building crane main and auxiliary hooks have an electrical interlock system to prevent their potential movement over spent fuel.

Additional information may be found in Unit 1 FSAR Section 10.20 and Unit 2 FSAR Section 9.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

For reference, refueling platform equipment [F15], is discussed in Section 2.3.4.2.

Intended Functions

T31-02 – Reactor Building Crane. The reactor building crane provides the ability to handle the large loads encountered with performing refueling operations and maintenance to the reactor building. The load bearing components must maintain their passive structural integrity function within the scope of license renewal.

Component Groups Requiring an Aging Management Review

Table 2.3.4-13 Components Supporting Reactor Building Crane [T31] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Structural Steel	Structural Support	Carbon Steel

2.3.4.14 Tornado Vents System [T38]

System Description

The purpose of the tornado vents is to act as blowout panels for venting the reactor and control building roofs under the following conditions:

- Against a wind velocity of 300 mph.
- When the internal static pressure in the building is increased to 55 lb/ft^2.
- When the temperature reaches approximately 212 °F.

A rapid depressurization of air surrounding site structures can occur if a tornado funnel suddenly engulfs a structure. Venting is accomplished by placing blowout panels, designed to fail at a pressure lower than the safe building capability for internal pressure, to relieve excess pressure in all essential parts of such structures.

Additional information may be found in Unit 2 FSAR paragraph 3.3.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T38-01 – Pressure Equalization. The reactor building tornado relief vents are safety related because they are required to maintain secondary containment during normal operation and during an earthquake. An inadvertent opening of the tornado vents could compromise secondary containment integrity and therefore the tornado vents are relied upon to remain closed to prevent or mitigate the consequences of accidents that could result in potential offsite exposure. The opening of the vents during a tornado is a safety function to prevent collapse of safety-related structures.

Component Groups Requiring Aging Management Review

Table 2.3.4-14 Components Supporting Tornado Relief Vent Assemblies [T38] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Screws*	Structural Support	Stainless Steel
Support Frame	Structural Support	Aluminum
Tornado Relief Vent Dome	Fission Product Barrier	Acrylic (Plexiglas G Cellcast Acrylic Polymer)

* No aging effects requiring management

2.3.4.15 Reactor Building HVAC System [T41]

System Description

The purposes of the reactor building HVAC system are to:

- Provide an environment with controlled temperature and airflow to ensure the comfort and safety of operating personnel and to optimize equipment performance by the removal of the heat dissipated from the plant equipment.
- Promote air movement from operating areas and areas of lower airborne radioactivity potential to areas of greater airborne radioactivity potential prior to final filtration and exhaust.
- Minimize the release of potential airborne radioactivity to the environment during normal plant operation by exhausting air, through a filtration system, from the areas in which a significant potential for radioactive particulates and/or radioiodine contamination exists.
- Provide a source of cooling to support the operation of the emergency core cooling systems (ECCS).
- Provide isolation capability to maintain secondary containment integrity and support operation of the standby gas treatment system (SGTS).

The reactor building HVAC system utilizes a combination of air conditioning, heating, and once-through ventilation. Heat removal is provided by the ventilation air and by the chilled-water (Unit 2 only) and service-water cooling coils served by the reactor and radwaste building chilled water system and the plant service water (PSW) system, respectively. Hot water heating coils, served by the plant heating system, are provided for heating.

Additional information may be found in Unit 1 FSAR Section 10.9 and Unit 2 FSAR subsection 9.4.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T41-01 – Indirect Radioactive Release Control. The reactor building HVAC system minimizes the release of potential airborne radioactivity during normal plant operation by promoting air movement from areas of lower airborne radioactivity to areas with potentially greater airborne radioactivity before final filtration and exhaust. This function also monitors the exhaust air stream for high radiation, shuts down the normal supply and exhaust systems, and initiates the SGTS.

The reactor building ventilation radiation monitoring signals that control the indirect radioactive release to the environment via the SGTS are evaluated as part of system D11. Indirect radioactive release control is the safety-related function. Dampers of the reactor building HVAC system are safety related per Criterion 3 and required for SGTS operation.

The associated T41 ductwork, which is considered nonsafety related, must retain its integrity to ensure that the SGTS can maintain a negative pressure in the reactor building. EQ criteria are selected for the isolation dampers and associated controls.

<u>T41-02 – Essential Mechanical/Environmental Support – ECCS Room Coolers.</u> The reactor building HVAC system provides a cooling source to support the operation of the ECCS pumps. The ECCS and corner room coolers described above have been designed to operate during and following a design basis accident to support the operation of those systems required to mitigate the consequences of an accident. The reactor core isolation cooling (RCIC) and control rod drive (CRD) room coolers are not included in this function.

<u>T41-07 – Essential Mechanical/Environmental Support – RCIC and CRD Room Coolers.</u> The room coolers for the RCIC and the CRD pump rooms provide reliable operation of the RCIC and CRD pumps. The RCIC and CRD pump room cooling units are not required for a safe plant shutdown following major accidents. The RCIC and CRD pump room cooling unit coils are treated as safety related with respect to maintaining the pressure boundary of the PSW system.

Component Groups Requiring an Aging Management Review

Table 2.3.4-15 Components Supporting Reactor Building HVAC System [T41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Fission Product Barrier, Pressure Boundary	Carbon Steel
Ductwork	Fission Product Barrier, Pressure Boundary	Galvanized Steel
Flow Element	Pressure Boundary	Stainless Steel
Tubing	Pressure Boundary	Copper Alloy

2.3.4.16 Traveling Water Screens/Trash Racks System [W33]

System Description

The purpose of the traveling water screens is to prevent debris from entering the portion of the intake structure from which the pumps take suction.

Larger debris are prevented from reaching the screens by the trash racks. The screen system is composed of two traveling screens, two motors, and two screen wash lines which operate in parallel to serve the common bay from which both the Unit 1 and Unit 2 pumps take suction. The specifications for both the trash racks and traveling screens require that they maintain their structural integrity following a design basis earthquake (DBE). Therefore, the pumps would continue to be protected from river debris by both the trash racks and the screens.

The normal environment for the traveling screens and trash racks is submerged in river water.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

W33-01 – Intake Structure Trash Removal. The intake structure is equipped with trash screens and rakes to keep debris out of the pump wells. The debris is removed from the screens by the screen wash water. The screens and rakes must remain structurally intact during an accident but are not required to move. Therefore, only the screens and rakes are in scope, not the motors or screen wash lines.

W33-03 – Screen Wash Isolation. Screen wash isolation in safe shutdown (SSD) mode is required during a fire to maintain SSD paths 1 and 3.

Component Groups Requiring an Aging Management Review

Table 2.3.4-16 Components Supporting Traveling Water Screens/ Trash Rack System [W33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Sight Glasses*	Pressure Boundary	Ceramic
Trash Racks	Debris Protection	Carbon Steel
Traveling Screen	Debris Protection	Carbon Steel Stainless Steel Copper Alloy*
Valve Bodies	Pressure Boundary	Carbon Steel

* No aging effects requiring management

2.3.4.17 Outside Structures HVAC System [X41]

System Description

The purpose of the intake structure HVAC system is to protect the intake structure equipment from adverse temperature conditions that could affect the reliability of the equipment. The diesel generator building HVAC system protects diesel generator building equipment from adverse temperature conditions that could affect the reliability of the equipment.

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

The diesel generator rooms' heating and ventilating systems consist of one power roof exhaust ventilator in each room for exhausting heat from the rooms when the generator is shut down and two 100% capacity power roof exhaust ventilators in each room for exhausting heat from the rooms during generator actuation. Two motor-operated wall air intake louvers, with fire dampers in each room, replenish the air removed by the exhaust ventilation. One louver serves as the air intake to the generator area; the other serves as the air intake to the battery rooms through the generator area.

Additional information about the system may be found in Unit 2 FSAR subsections 9.4.5 and 9.4.10.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

X41-01 – Intake Structure Environmental Control. The intake structure HVAC system controls the temperature of the intake structure to ensure optimal equipment performance. This system assures that the intake structure bulk air temperature remains within a band of 40 °F to 122 °F given an outside air temperature band of 10 °F to 95 °F. This system operates from normal and emergency power sources and performs its function before, during, and after a design basis accident (DBA).

X41-02 – EDG Building Environmental Control. The EDG HVAC system provides temperature and air movement control to prevent the ambient temperatures in the EDG room from exceeding the maximum allowable temperature of 122 °F when the diesel is running.

X41-03 – EDG Building Battery Room H_2 Control. The EDG battery room ventilation system exhausts hydrogen from the battery rooms.

X41-04 – EDG Switchgear Room Heating and Ventilation. The EDG switchgear room heating and ventilation exhausts heat from the switchgear rooms and maintains a minimum temperature in the room.

X41-05 – EDG Building Oil Storage Room Ventilation. This function exhausts fumes from the oil storage room in the event of fire.

Component Groups Requiring an Aging Management Review

Table 2.3.4-17 Components Supporting Outside Structures HVAC System [X41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Duct Sleeve	Pressure Boundary	Carbon Steel
Flow Element	Pressure Boundary	Stainless Steel
Grating*	Missile Barrier	Carbon Steel
Tubing	Pressure Boundary	Copper

* No aging effects requiring management

2.3.4.18 Fire Protection System [X43]

System Description

The fire protection program assures, through a defense-in-depth design, that a fire will not prevent the necessary safe plant shutdown functions from occurring. Increases in the risk of radioactive releases to the environment could occur without the fire protection program. The program consists of detection and extinguishing systems, administrative controls and procedures, and trained personnel. The defense-in-depth principle is aimed at achieving an adequate balance in these areas along with:

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

Primary design consideration is given to locating redundant safe shutdown circuits and components in distinct areas separated by fire barriers which prevent the propagation of fire to adjacent areas. The barriers are designed to contain a design basis fire which totally involves the combustibles in the given area.

A state-of-the-art, early warning fire detection multiplex system is utilized. The system is configured around master/slave concept linked to a common command center. All devices (e.g., detectors, tamper switches, pressure switches, etc.) are wired to their respective slave panels. Signals from each of these devices are grouped according to their originating detection zone. There are approximately 260 detection zones throughout both units.

Water supply for the fire protection system inside the protected area is provided by two 300,000 gallon dedicated storage tanks. The tanks are supplied by two deep wells, each with a 700 gpm makeup pump, capable of refilling either tank within 8 hours. These water supplies are strained and filtered for normal makeup.

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

Additional information may be found in the Hatch Fire Hazards Analysis (FHA).

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

X43-01 – Cardox Fire Suppression for EDGs. The cardox fire suppression for EDGs provides an automatic gaseous total flooding fire suppression system for diesel engine compartment fire to contain and control the level of fire damage. The scope includes a rollup fire door, HVAC fire dampers, carbon dioxide discharge controls, and detection devices. The rollup fire door releasing mechanism is controlled by a nonsafety-related fusible link.

X43-02 – Halon Suppression-Remote Shutdown Panel (Unit 2). The halon suppression-remote shutdown panel provides the automatic suppression system to comply with separation requirements of safe shutdown paths located inside the remote shutdown panels according to 10 CFR Appendix R.

X43-04 – Plant Wide Fire Suppression With Water. Dedicated water storage and plantwide water distribution system to supply manual hose stations and automatic water suppression systems for areas of Plant Hatch.

This is applicable to portions of L43, T43, U43, V43, W43, X43, Y43, and Z43. The fire protection water supply is furnished from deep wells and stored in tanks. All powerblock structures consist of looped headers and dual feeds from the underground loop mains. The distribution headers supply risers for hose stations and risers for the suppression systems where practical. The water curtains in the reactor building provide separation of safe shutdown paths by serving as an equivalent fire barrier.

X43-06 – Fire Detection. Provide early warning fire detection systems to alert station personnel of incipient stage of fire development to ensure fast and timely response.

This is applicable to portions of L43, T43, U43, W43, X43, Y43, and Z43. Fire detection is necessary to comply with the original license basis described in Fire Hazards Analysis, Appendix D, and to comply with 10 CFR 50 Appendix R requirements detailed in the Plant Hatch FHA, Appendix E.

X43-07 – Penseals and Fire Barriers for Preventing Fire Propagation. Fire barriers consist of fire-rated doors, dampers, and penetration seals for the respective buildings and provide separation between safe shutdown trains to ensure a fire in any single area will not prevent safe shutdown.

This is applicable to portions of L48, R90, T43, U43, X43, and Z43. Fire barriers consist of fire doors, fire dampers, and barrier penetration seals to provide passive protection features to maintain cable separation and restrict fire to a single fire area as required under 10 CFR 50 Appendix R.

X43-08 – Manual Carbon Dioxide Fire Protection. Provide first response fire fighting capability with carbon dioxide hose reels to reduce cleanup and prevent water damage to high voltage electrical equipment. This applies only to X43. Manual hose reels are provided as an alternative to water-based hose stations.

X43-10 – Cardox Fire Suppression for the Computer Room. Provide an automatic gaseous fire suppression system for the computer room and the cable spreading room. This is a total flooding system actuated by ionization detection.

Component Groups Requiring an Aging Management Review

Table 2.3.4-18 Components Supporting Fire Protection System [X43] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Fire Doors	Fire Barrier	Carbon Steel Galvanized Steel Copper Alloy Stainless Steel Aluminum Nonmetallic, Inorganic-Gypsum Fibers, nonasbestos synthetic Nonmetallic, organic
Fire Hydrants	Pressure Boundary	Cast Iron
Fittings	Pressure Boundary	Cast Iron
Fittings	Pressure Boundary	Copper Alloy Cast Iron
Fusible Material	Pressure Boundary	Nonferrous Metal
Kaowool Hold-down Straps	Fire Barrier	Galvanized Steel
Nozzles	Flow Restriction	Aluminum Copper Alloy
Nozzles	Flow Restriction	Copper Alloy
Penetration Seals	Fire Barrier	Concrete Ceramics Carbon Steel Synthetic Fiber Elastomers
Pilot Valves	Pressure Boundary	Aluminum
Pipe Line Strainers	Pressure Boundary	Cast Iron
Piping	Pressure Boundary	Carbon Steel Aluminum Galvanized Steel Copper Alloy Cast Iron
Piping	Pressure Boundary	Carbon Steel Stainless Steel
Piping	Pressure Boundary	Carbon Steel Galvanized Steel
Pump Casings	Pressure Boundary	Cast Iron
Restricting Orifices	Pressure Boundary, Flow Restriction	Stainless Steel
Sprinkler Head Bulbs	Pressure Boundary	Ceramics

Table 2.3.4-18 Components Supporting Fire Protection System [X43] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Material
Sprinkler Head Links	Pressure Boundary	Copper
Sprinkler Heads	Flow Direction, Pressure Boundary, Flow Restriction	Stainless Steel Copper Alloy Carbon Steel
Strainer Basket	Pressure Boundary	Stainless Steel
Strainers	Pressure Boundary	Cast Iron
Tank	Pressure Boundary	Carbon Steel
Tank Insulation	Environmental Control	Organic
Tubing	Pressure Boundary	Copper Alloy
Tubing Fittings	Pressure Boundary	Copper Alloy Cast Iron Copper
Valve Bodies	Pressure Boundary	Carbon Steel Cast Iron Copper Alloy

2.3.4.19 Fuel Oil System [Y52]

System Description

The purpose of the fuel oil system is to receive, store, and supply fuel oil to other systems.

Fuel oil is provided to the diesel generator system. Diesel engine fuel for Units 1 and 2 is stored in five interconnected buried tanks. Diesel fuel is transferred to the engine day tanks using dedicated, redundant transfer pumps and piping. The diesel fuel storage tanks are filled by gravity from a truck connection through a common header.

Two of the buried tanks are dedicated to each of the Unit 1 and Unit 2 diesel generators. The remaining tank is used to supply the swing diesel (1B) to serve either Unit 1 or Unit 2. The fuel oil system transfer pumps operate continuously on demand from the day tank level controllers. Storage tank levels are monitored and alarmed (low level) in the main control room (MCR).

Additional information may be found in Unit 1 FSAR Section 8.4 and Unit 2 FSAR subsection 9.5.4.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>Y52-01 – Emergency Diesel Generator (EDG) Fuel Oil Supply.</u> The EDG fuel oil system provides a 7 day supply of fuel oil to the diesels in the event of a loss of offsite power (LOSP). The availability of the storage tanks is needed for an extended duration LOSP, which is a more risk-significant LOSP event. This function also includes the fuel oil supply piping and the R43 instrumentation and valves in the piping from the fuel oil pumps to the EDGs.

Component Groups Requiring an Aging Management Review

Table 2.3.4-19 Components Supporting Fuel Oil System [Y52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Discharge Head	Pressure Boundary	Carbon Steel
Flex Hose	Pressure Boundary	Stainless Steel
Manway Shell	Shelter/ Protection	Carbon Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Pump	Pressure Boundary	Carbon Steel
Strainer Basket	Shelter/ Protection	Stainless Steel
Tank	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.20 Control Building HVAC System [Z41]

System Description

The control building HVAC system performs the following functions under normal and post accident conditions of the plant:

- Provides temperature control and air movement control, including a filtered fresh-air supply, for personnel comfort.
- Optimizes equipment performance by the removal of the heat dissipated from the plant equipment.
- Minimizes the potential of exhaust air entering into the supply air intake by exhausting at an elevated point via the reactor building vent plenum.
- Detects and limits the introduction of radioactive material into the main control room (MCR).

The control building is served by both heating and air-conditioning (A/C) subsystems and a once-through ventilation subsystem. The A/C subsystems use direct expansion of chilled water cooling coils. Heating is provided by electric or hot water heating coils. The control room, computer room, water analysis room, chemistry laboratory and health physics area, and cold laboratory are the areas served by the heating and A/C subsystems. The low pressure coolant injection (LPCI) inverter room and Unit 2 vital A/C room are served by separate coolers. All other areas of the control building are served by a once-through ventilation subsystem.

For additional information see Unit 2 FSAR subsection 9.4.7.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>Z41-02 – Control Room Habitability.</u> The control room HVAC system is designed to provide cooling and a controlled environment for personnel safety and habitability in the control room during normal and accident conditions. Also, the system provides a controlled temperature to ensure the integrity of the MCR components. The MCR environmental control system, in the pressurization mode, ensures operator protection and habitability in the MCR in the event of design basis accidents.

<u>Z41-03 – Control Building Environmental Support.</u> Control building HVAC provides temperature and air movement control, and removes heat dissipated from the plant equipment for the computer room, radiochemistry lab and health physics area, water analysis room, CO_2 storage tank room, station battery rooms, shift supervisor’s area, Unit 1 vital AC room and cold laboratory. This function also minimizes the potential of airborne radioactivity in the health physics area.

Component Groups Requiring an Aging Management Review

Table 2.3.4-20 Components Supporting Control Building HVAC System [Z41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Accumulator Air Valve	Pressure Boundary	Carbon Steel
Accumulator Piping	Pressure Boundary	Carbon Steel
Accumulator Tanks	Pressure Boundary	Stainless Steel
Bolting	Pressure Boundary	Carbon Steel
Duct Gasket	Pressure Boundary	Fibers, Nonasbestos Synthetic; Elastomers, other
Duct Heater	Pressure Boundary	Aluminum
Duct Silencer	Pressure Boundary	Galvanized Steel
Ductwork	Pressure Boundary	Carbon Steel
Ductwork	Pressure Boundary	Galvanized Steel
Ductwork Flex Connector	Pressure Boundary	Fibers, Nonasbestos Synthetic; Elastomers, other
Filter Housing	Pressure Boundary	Galvanized Steel
Flow Element	Pressure Boundary	Stainless Steel
Instrument Piping	Pressure Boundary	Copper Alloy
Instrument Piping	Pressure Boundary	Stainless Steel
Louver	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Radiation Element	Pressure Boundary	Stainless Steel
Temperature Sensor	Pressure Boundary	Stainless Steel
Tubing	Pressure Boundary	Copper
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.5 STEAM AND POWER CONVERSION SYSTEMS

2.3.5.1 Electro-Hydraulic Control System [N32]

System Description

The purpose of the electro-hydraulic control (EHC) system is to provide control of reactor pressure during reactor startup, power operation, and shutdown. EHC also provides a means of controlling main turbine speed and acceleration during turbine startup and protect the main turbine from undesirable operating conditions by initiating alarms, trips, and runbacks.

Additional information about this system may be found in Unit 1 FSAR Section 11.2 and Unit 2 FSAR Section 10.2A.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

N32-02 – Main Turbine Pressure Regulators. Controls turbine control valve position by adjusting EHC pressure based on main steam pressure. The EHC regulators in the scope of license renewal are 1N11-N042A/B and 2N32-N301A/B. Technical specifications do not require the regulators to be operable. However, transient analysis takes credit for the backup pressure regulator to function to prevent fuel damage in the event of a downscale failure of the inservice regulator. Therefore these regulators were included for conservatism.

Component Groups Requiring an Aging Management Review

Table 2.3.5-1 Components Supporting Electro-Hydraulic Control [N32] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Piping	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.5.2 Main Condenser System [N61] (Unit 2 Only)

System Description

The main condenser provides a heat sink for turbine exhaust steam, turbine bypass steam, and other flows such as cascading heater drains, air ejector condenser drains, exhaust from the feed pump turbines, gland seal condenser, feedwater heater shell operating vents, and condensate pump suction vents. The main condenser also deaerates and provides storage capacity for the condensate water to be reused.

The main condenser system is a two-shell, single-pass, divided water box, deaerating type designed for condenser duty of 5.66 x 10^9 Btu/h, an inlet water temperature of 90 °F, and an average back pressure of 3.5 in. Hg absolute. During plant operation, steam from the last-stage, low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several others flows, such as exhaust steam from the feed pump turbines, cascading heater drains, air ejector condenser drain, gland-seal condenser drain, feedwater heater shell operating vents, and condensate pump suction vents.

Other flows occur periodically. These originate from condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low-point drains, extraction steam spills, makeup, and condensate.

During abnormal conditions, the condenser is designed to receive (not simultaneously) turbine bypass steam, feedwater heater high-level dumps, and relief valve discharge from feedwater heater shells, steam-seal regulator, and various steam supply lines.

Additional information may be found in Unit 2 FSAR subsection 10.4.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

N61-03 – Post Accident Radioactive Decay Holdup. The post accident radioactive decay holdup provides a method for MSIV leakage treatment. It uses the main steam drain lines to convey the MSIV leakage during post-accident conditions to the isolated main condenser. The main condenser provides holdup and allows “plate-out” of the fission products that may leak out from the closed MSIV during post-accident conditions. MSIV leakage that enters the condenser is ultimately released to the turbine building as noncondensible gases through the low pressure turbine seal after significant plate-out of iodine.

Component Groups Requiring an Aging Management Review

Table 2.3.5-2 Components Supporting Main Condenser System [N61] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Condenser Shell	Fission Product Barrier Pressure Boundary	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Preheater	Pressure Boundary Fission Product Barrier	Carbon Steel
Preheater	Pressure Boundary Fission Product Barrier	Stainless Steel
Restricting Orifices	Pressure Boundary Fission Product Barrier	Stainless Steel
Strainer	Pressure Boundary Fission Product Barrier	Carbon Steel
Thermowell	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.4 STRUCTURES SCREENING RESULTS

The following system descriptions are included to provide the reader with the following information:

- A general description of the system and its purpose;
- The intended functions associated with that system;
- A list of the various civil/structural component groups that are subject to an aging management review.

Note that the intended functions define the boundaries by which various component groups are analyzed for aging management purposes. The system description is informational and is not intended to define boundaries.

2.4.1 PIPING SPECIALTIES [L35]

System Description

Piping specialties provide support for essential piping systems. Essential piping systems are required to maintain the integrity of safety-related and nonsafety-related systems during normal operations and transient/accident mitigation. These specialties include snubbers and pipe restraints regardless of system affiliation and also include non ASME HVAC duct supports and tube trays.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

L35-01 – Pipe Supports. Pipe supports for the reactor coolant system and subsystems are provided to ensure pressure retaining capability of the piping systems due to weight, seismic, and fluid dynamic loads. Pipe supports maintain the integrity of nonsafety functions during accident and seismic events. This includes all safety-related plant pipe supports, pipe restraints, and tubing supports regardless of master parts list (MPL) designation.

L35-02 – Nonseismic Pipe Supports. Pipe supports for nonsafety-related piping (nonseismic category) located throughout the plant are included in this function. These supports are not designed to any seismic criteria but are designed for dead weight and thermal loads only. Only those seismic category II piping supports required to support functions X43-04, W33-03, and N61-03 are included within the scope of license renewal. All other seismic category II supports are excluded from the scope of license renewal.

Component Groups Requiring an Aging Management Review

Table 2.4.1-1 Components Supporting Piping Specialties [L35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Hangers and Supports for ASME Class I Piping	Structural Support	Carbon Steel Galvanized Steel Stainless Steel*
Hangers and Supports for Non ASME Class I Piping, Tubing, and Ducts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel
Tube Trays and Covers	Structural Support; Nonsafety Related Structural Support	Stainless Steel*

* No aging effects requiring management

2.4.2 CONDUITS, RACEWAYS, AND TRAYS [R33]

System Description

The purpose of the conduits, raceways, and trays system is to provide support for a cable system with cables and penetrations selected, routed, and located to survive the design basis events established for this plant and prevent a loss of function of any system due to a cable failure.

Additional information may be found in Unit 1 FSAR Section 8.8 and Unit 2 FSAR Section 8.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R33-01 – Wire and Cable Integrity. The conduits, raceways, and trays that are mounted Seismic Category I are considered safety-related. Seismic Category I conduits, raceways and trays provide support for essential cable feeding power supplies and controls.

R33-02 – Wire and Cable Integrity- Nonsafety Related: The conduits, raceways and trays that are neither mounted Seismic Category I nor Seismic Category II/I are considered nonsafety-related. Nonsafety-related conduits, raceways and trays provide support for non-essential cable feeding power supplies and controls. Also, some nonseismic raceways are included in safe shutdown pathways.

Component Groups Requiring an Aging Management Review

Table 2.4.2-1 Components Supporting Cable Trays and Supports [R33] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Cable Trays and Supports	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Aluminum*

* No aging effects requiring management

2.4.3 PRIMARY CONTAINMENT [T23]

System Description

The purpose of the primary containment is to isolate and contain fission products released from the reactor primary system following a design basis accident (DBA) and to confine the postulated release of radioactive material.

The primary containment design employs a pressure suppression containment system which houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the reactor primary system. The pressure suppression system consists of a drywell, a pressure suppression chamber (torus) which stores a large volume of water, a connecting vent system between the drywell and the pressure suppression pool, isolation valves, vacuum relief system, containment cooling systems, and other service equipment.

The pressure suppression chamber is a steel pressure vessel in the shape of a torus located below and encircling the drywell, with a major diameter of approximately 107 ft and a cross-sectional diameter of approximately 28 ft. The pressure suppression chamber contains the suppression pool and the air space above the pool. The suppression chamber transmits seismic loading to the reinforced concrete foundation slab of the reactor building. Space is provided outside of the chamber for inspection.

Additional information about this system may be found in Unit 1 FSAR subsection 5.1.2 and Unit 2 FSAR subsection 6.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T23-01 – Torus/Drywell. The primary containment system provides, in conjunction with other safeguard features, the capability to limit the release of fission products in the event of a postulated DBA so that offsite doses do no exceed 10 CFR 100 guidelines. The pressure suppression pool initially serves as a heat sink for any postulated transient or accident condition in which the normal heat sink (main condenser or shutdown cooling system) is unavailable.

Component Groups Requiring an Aging Management Review

Table 2.4.3-1 Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel
Blind Flange*	Fission Product Barrier	Carbon Steel
Containment Isolation Valves *	Fission Product Barrier	Carbon Steel
Containment Isolation Valves*	Fission Product Barrier	Stainless Steel
Containment Penetrations (Mechanical only)	Fission Product Barrier	Carbon Steel Stainless Steel
Miscellaneous Steel	Structural Support; Radiation Shielding; Pipe Whip Restraint; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Piping*	Fission Product Barrier	Carbon Steel
Piping*	Fission Product Barrier	Stainless Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding	Concrete Carbon Steel
Steel Bellows (inside Vent Pipe)	Pressure Boundary; Fission Product Barrier	Carbon Steel Stainless Steel
Structural Steel	Structural Support; Shelter/Protection; Radiation Shielding; Missile Barrier; HE/ME Shielding; Pipe Whip Restraint; Nonsafety Related Structural Support; Pressure Boundary Fission Product Barrier; Exchange Heat	Carbon Steel Stainless Steel
Tubing*	Fission Product Barrier; Pressure Boundary	Stainless Steel
Unreinforced Concrete	Radiation Shielding	Unreinforced Concrete**
Vent Pipe, Vent Header, Downcomers	Fission Product Barrier; Pressure Boundary	Carbon Steel

* Piping and valves include components from systems P51, P21, T23, G51, G11, D11, and C51. These are all included in function T23-01, Torus/Drywell.
** No aging effects requiring management

2.4.4 FUEL STORAGE [T24]

System Description

The purpose of the fuel storage system is to provide specially designed underwater storage space for the spent-fuel assemblies which require shielding during storage and handling. The fuel storage facility is located inside the secondary containment on the refueling floor.

Additional information may be found in Unit 1 FSAR Section 10.2, 10.3 and Unit 2 FSAR Section 9.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T24-01 – Spent Fuel Integrity. The fuel storage facility provides specially designed underwater storage space for the spent fuel assemblies which require shielding and cooling during storage and handling. This includes the spent fuel pool, concrete vault and stainless steel liner, fuel pool gates, fuel racks, and other equipment necessary to properly store irradiated fuel and components.

T24-02 – New Fuel Integrity. The fuel storage facility provides specially designed dry, clean storage areas for the new fuel assemblies. This includes the concrete vault and fuel racks.

Component Groups Requiring an Aging Management Review

Table 2.4.4-1 Components Supporting Fuel Storage [T24] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support	Stainless Steel
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Fission Product Barrier	Stainless Steel
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Reinforced Concrete	Shelter/Protection; Structural Support; Nonsafety Related Structural Support	Concrete Carbon Steel
Seismic Restraints for Spent Fuel Storage Racks	Structural Support	Aluminum
Storage Racks*	Structural Support	Aluminum
Structural Steel	Shelter/Protection; Fission Product Barrier; Structural Support	Stainless Steel

* No aging effects requiring management

2.4.5 REACTOR BUILDING [T29]

System Description

The purpose of the reactor building is to shelter and support the refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment.

The building is a reinforced concrete structure with a steel superstructure. The building consists of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete exterior walls and prestressed exterior wall panels.
- Reinforced concrete floors with reinforced concrete beams and girders framing.
- Reinforced concrete interior walls with some blockouts filled with concrete masonry.
- Reinforced concrete roof slab on metal roof deck system supported by steel superstructure.

The reactor building completely encloses the reactor and its pressure suppression primary containment system. Also housed within the reactor building are the core standby cooling systems, reactor water cleanup demineralizer system, standby liquid control system, control rod drive system, reactor protection system, and electrical equipment components. The building is designed for minimum leakage so that the standby gas treatment system (SGTS) has the necessary capacity to reduce and hold the building at a subatmospheric pressure under normal wind conditions.

Additional information may be found in Unit 1 FSAR subsection 12.2.1 and Unit 2 FSAR Section 3.0.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T29-01 – Containment and Support. The reactor building provides primary containment during reactor refueling and maintenance operations when the primary containment is open. It also provides an additional barrier when the primary containment system is functional. Therefore, it is relied on to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines. This evaluation includes the blowout panels in the pipe-chase between the reactor building and the turbine building.

Component Groups Requiring an Aging Management Review

Table 2.4.5-1 Components Supporting Reactor Building [T29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Blowout Panels*	Structural Support; Fission Product Barrier	Aluminum
Miscellaneous Steel	Structural Support; HE/ME Shielding; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel*
Panel Joint Seals and Sealants	Shelter/Protection; Fission Product Barrier	Elastomers Nonmetallic, Inorganic
Reinforced Concrete	Structural Support; Fire Barrier; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding; Nonsafety Related Structural Support	Concrete Masonry Block Carbon Steel
Structural Steel	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel

* No aging effects requiring management

2.4.6 DRYWELL PENETRATIONS [T52]

System Description

The purpose of the drywell penetrations is to provide a path for cable currents/signals to pass through primary containment to support the various modes of operation of their associated systems while maintaining primary containment integrity.

Mechanical penetrations are discussed in Section 2.4.3 (Primary Containment [T23]).

Containment penetrations include electrical penetration assemblies in addition to the mechanical penetrations referenced above. Electrical penetrations are hermetically sealed penetrations which are welded to the primary containment shell plate. They must maintain their primary containment pressure integrity function during all postulated operating and accident conditions. They are designed for the same pressure and temperature conditions as the drywell and pressure suppression chamber.

For additional information see Unit 1 FSAR Section 5.2 and Unit 2 FSAR subsection 6.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T52-01 – Primary Containment Integrity. The penetrations provide a path for cable currents/signals to pass through primary containment to support the various modes of operation of the systems associated with the cables.

Component Groups Requiring an Aging Management Review

Table 2.4.6-1 Components Supporting Drywell Penetrations [T52] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Structural Steel	Fission Product Barrier	Carbon Steel

2.4.7 REACTOR BUILDING PENETRATIONS [T54]

System Description

The purpose of the reactor building penetrations is to allow mechanical and electrical equipment and personnel to pass through secondary containment to support the various modes of operation of their associated systems while maintaining secondary containment integrity.

Penetrations for piping and ducts are designed for leakage characteristics consistent with containment requirements for the entire building. Electrical cables and instrument leads pass through ducts sealed into the building wall.

Additional information may be found in Unit 1 FSAR paragraph 5.3.3.2 and Unit 2 FSAR figure 8.3-11.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T54-01 – Secondary Containment Integrity. Reactor building electrical and mechanical penetrations allow piping and conductors to penetrate the secondary containment boundary and maintain secondary containment leakage rates within design limits.

This function includes the structural support feature of Nelson Frames. The electrical aspect of Nelson Frames is included as part of Electrical Screening (See Table 2.5.15-1.).

Component Groups Requiring an Aging Management Review

Table 2.4.7-1 Components Supporting Reactor Building Penetrations [T54] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Structural Steel	Fission Product Barrier	Carbon Steel Galvanized Steel

2.4.8 TURBINE BUILDING [U29]

System Description

The purpose of the turbine building is to house the turbine-generator and associated auxiliaries including the condensate and feedwater systems.

The turbine building is a steel and concrete structure consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete floors self-supporting or supported by structural steel framing.
- Reinforced concrete or concrete block interior walls.
- Reinforced concrete turbine pedestal resting on concrete mat foundation.
- Reinforced concrete exterior walls.
- Reinforced concrete slab on metal roof deck system supported by steel framing.

Additional information may be found in Unit 1 FSAR subsection 12.2.2 and Unit 2 FSAR Section 3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

U29-01 – BOP Equipment Integrity and Support. There is no equipment or instrumentation located in the turbine building proper which would preclude the ability to shut down the reactor safely if damaged from a high-energy line failure. The turbine building is designed and constructed to ensure that it will not damage Category I structures or equipment located inside or adjacent to it in the event of a design basis event (DBE).

The cable chase area below elevation 147 ft is designed to Seismic Category I criteria. The Seismic Category I barrier between the main steam and feedwater piping located above elevation 147 ft and the cable chase area below precludes any adverse direct effects of postulated failure of the main steam or feedwater piping in the turbine building on the cables. The cables in this area provide trip inputs for the recirculation pump trip and reactor scram following generator load rejection or turbine trip originating in the turbine building. Based on these considerations, the portions of the Unit 1 turbine building and the cable chase area below elevation 147 ft are in scope for license renewal. The portions of the Unit 2 turbine building and the cable chase area below elevation 147 ft are in scope, as well as the supports over the radioactive release pathway for the main condenser.

Component Groups Requiring an Aging Management Review

Table 2.4.8-1 Components Supporting Turbine Building [U29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Radiation Shielding; Nonsafety Related Structural Support	Concrete Masonry Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

2.4.9 INTAKE STRUCTURE [W35]

System Description

The purpose of the intake structure is to protect residual heat removal service water and plant service water equipment from the influence of environmental conditions such as flooding, earthquakes, and tornadoes.

The intake structure is a concrete and steel structure consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete exterior walls and internal walls.
- Reinforced concrete floors and roof.
- Structural steel framing and grating, steel water spray and internal missile shield barriers, stairs, and platforms.

Unit 1 shares the intake structure with Unit 2. The intake structure has labyrinth access openings for protection against tornado missiles.

Additional information may be found in Unit 1 FSAR subsection 12.2.7 and Unit 2 FSAR subsection 3.8.4.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

W35-01 – RHRSW and PSW System Integrity. The intake structure is designed to protect equipment essential for plant shutdown from the influence of environmental conditions, such as flooding, earthquake, and tornadoes. The intake structure is a Seismic Category I structure.

Component Groups Requiring an Aging Management Review

Table 2.4.9-1 Components Supporting Intake Structure [W35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Flood Barrier; Missile Barrier; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Flow Direction; Missile Barrier; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel

2.4.10 YARD STRUCTURES [Y29]

System Description

The purpose of the yard structures is to provide equipment integrity and personnel habitability for various structures on the plant site.

Some of the structures included in Y29 are:

- The concrete wall and foundation accommodating the condensate storage tank.
- The foundation of the nitrogen storage tank.
- The service water valve pit boxes.
- The foundation for the fire pump house.
- The foundations for the two fire protection water storage tanks.
- The foundations for the two fire protection diesel pump fuel tanks.
- Underground concrete duct runs and pull boxes between Class I structures.

Additional information may be found in Unit 1 FSAR paragraph 5.2.3.9 and Unit 2 FSAR paragraph 3.8.5.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Y29-01 – Equipment Integrity and Personnel Habitability. The yard structures provide equipment integrity and personnel habitability for various structures listed in the system description above.

This function is brought into scope because of the Seismic Category I foundation supporting the liquid nitrogen tank. The liquid nitrogen tank provides the safety-related back-up supply of motive gas for the drywell inerting system (T48) and the drywell pneumatic system (P70). The FSAR discusses the reliance of the safety analysis upon the liquid nitrogen tank. In addition, Safe Shutdown Pathways 1 and 2 in the FHA rely upon the liquid nitrogen tank to achieve safe shutdown in the event of a fire.

With respect to the enclosure around the condensate storage tank (CST), the wall and the CST foundation are seismically qualified to Category 1 requirements.

The service water valve boxes are in scope as they contain inscope piping for P41 system. The concrete duct runs and pull boxes that traverse the yard between various Class I structures as well as turbine building are in scope. These duct runs are used for routing safety-related circuits and provide protection to them.

The foundations for the fire pump house, fire protection water storage tanks, and fire protection diesel pump fuel tanks are also in scope.

Component Groups Requiring an Aging Management Review

Table 2.4.10-1 Components Supporting Yard Structures [Y29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Cover Plates – Pull Boxes*	Shelter/Protection; Flood Barrier	Aluminum
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

* No aging effects requiring management

2.4.11 MAIN STACK [Y32]

System Description

The purpose of the main stack is to support and protect monitoring equipment and provide for the monitoring and elevated release of gaseous effluents from the main stack system.

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

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

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

Additional information may be found in Unit 1 FSAR subsection 5.3.4 and Unit 2 FSAR Section 11.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>Y32-01 – Gaseous Effluent Elevated Release.</u> The main stack houses equipment for monitoring gaseous effluent releases and assures elevated release of these gaseous wastes to the environment.

Component Groups Requiring an Aging Management Review

Table 2.4.11-1 Components Supporting Main Stack [Y32] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Stainless Steel* Copper Alloy (Bronze)*
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Nonsafety Related Structural Support; Fission Product Barrier; Radiation Shielding	Concrete Carbon Steel
Structural Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel*

* No aging effects requiring management

2.4.12 EDG BUILDING [Y39]

System Description

The purpose of the diesel generator building is to house the emergency diesel generators (EDG) and their accessories essential for safe plant shutdown for both Unit 1 and Unit 2.

The diesel generator building is a reinforced concrete structure consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete exterior walls and interior walls.
- Reinforced concrete roof and parapet wall.

The diesel generator building houses EDGs and their accessories. The diesel generator building has labyrinth access openings for protection against tornado missiles. The diesel generator building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomena.

Additional information may be found in Unit 1 FSAR subsection 12.2.6 and Unit 2 FSAR subsection 9.4.5.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Y39-01 – EDG and Equipment Integrity. The diesel generator building provides support and equipment integrity for the EDGs which provide essential ac supply.

Component Groups Requiring an Aging Management Review

Table 2.4.12-1 Components Supporting Emergency Diesel Generator Building [Y39] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Carbon Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Missile Barrier; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel

2.4.13 CONTROL BUILDING [Z29]

System Description

The purpose of the control building is to house the common control room for Units 1 and 2 and associated auxiliaries.

The building is a reinforced concrete structure with steel framing. The building consists of the following major structural components.

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

Additional information may be found in Unit 1 FSAR paragraph 12.3.3.1.1 and Unit 2 FSAR subsection 3.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Z29-01 – Equipment Integrity and Personnel Habitability. The control building includes the substructure, foundations, superstructure, walls, floors, and roof necessary to maintain equipment integrity and personnel habitability. The control building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomenon. Access doors are included in L48-01.

Component Groups Requiring an Aging Management Review

Table 2.4.13-1 Components Supporting Control Building [Z29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Carbon Steel
Blowout Panels*	Structural Support; Fission Product Barrier	Aluminum
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Carbon Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Missile Barrier; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

* No aging effects requiring management

2.5 ELECTRIC POWER AND INSTRUMENTATION AND CONTROLS SCREENING RESULTS

The following system descriptions are included to provide the reader with the following information:

- A general description of the system and its purpose;
- The intended functions association with that system; and
- A list of the various electrical component groups subject to an aging management review.

Note that the intended functions define the boundaries by which various component groups are analyzed for aging management purposes. The system description is informational and is not intended to define boundaries.

2.5.1 ANALOG TRANSMITTER TRIP SYSTEM [A70]

System Description

The purpose of the analog transmitter trip system (ATTS) is to monitor several critical plant parameters and provide actuation and trip signals to the following systems:

- Reactor Protection System
- Primary Containment Isolation System
- Secondary Containment Isolation System
- Core Spray System
- Residual Heat Removal System
- High Pressure Coolant Injection System
- Reactor Core Isolation Cooling
- Automatic Depressurization System
- Low-Low Set Logic
- Alternate Rod Insertion Logic
- Reactor Recirculation System
- Emergency Diesel Generators
- Safety Relief Valves

The ATTS is a solid-state electronic trip system designed to provide monitoring of process parameters. The system consists of primary sensors, master trip assemblies, slave trip assemblies, calibration units, card file assemblies, and other accessories.

Additional information may be found in Unit 1 FSAR Section 7.18 and Unit 2 FSAR Section 7.8.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

A70-01 – Process Parameter Monitoring. ATTS is an ESF support system, supporting the reactor protection system, emergency core cooling system, emergency diesel generators, low low set relief logic system, automatic depressurization system, primary containment isolation system, high pressure coolant injection, and reactor core isolation cooling by providing process parameter monitoring to allow these systems to initiate on appropriate actions.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.2 NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM [A71]

System Description

The purpose of the nuclear steam supply shutoff system is to isolate the reactor vessel and various other systems which carry radioactive fluids within the primary containment to prevent the release of radioactive materials.

Sensor elements are located in the reactor vessel, drywell, main steam lines (MSLs), MSL pipe chase, turbine building, the reactor water cleanup (RWCU) system, and areas around the RWCU system. The system functions are initiated when sensors actuate and provide input to relay control circuits, which in turn initiate the closure of containment isolation valves and initiate various other functions. The other functions include annunciation, post accident monitoring system recorder chart speed control, control room pressurization, and signal input to the primary containment isolation system.

Additional information may be found in Unit 1 FSAR subsection 7.3.4 and Unit 2 FSAR subsection 7.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

A71-01 – Signal Transmission. The system supports safety-related functions associated with the reactor, including all functions, such as, group isolation signals, system trip interlocks, control room annunciation, and control room pressurization initiation.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.3 PRIMARY CONTAINMENT ISOLATION SYSTEM [C61]

System Description

The purpose of the primary containment isolation system (PCIS) is to limit fission product releases by isolating fluid systems during accident/transient conditions.

The PCIS functions are initiated when sensors monitoring critical parameters activate and provide input to relay control circuits which in turn initiate closure of containment isolation valves or initiate various other functions. The other functions include initiating SGTS, isolating reactor building ventilation, isolating refueling floor ventilation, and isolating the off-gas system exhaust.

Additional information may be found in Unit 1 FSAR Section 7.3 and Unit 2 FSAR subsection 7.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C61-01 – Primary Containment Isolation. The PCIS includes the instrumentation, controls, and actuators to perform the isolation function regardless of the master parts list (MPL) designation. Primary containment isolation limits fission product releases by isolating fluid systems during accident/transient conditions.

C61-02 – Signal Transmission. Primary containment isolation provides initiation signals to SBGT. Sensor input signals initiate automatic closure of primary containment isolation valves.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.4 REACTOR PROTECTION SYSTEM [C71]

System Description

The purpose of the reactor protection system (RPS) is to provide protection against the onset and consequences of conditions that challenge the integrity of the fuel barriers and the nuclear system process barrier by the initiation of an automatic scram.

The RPS is composed of two independent, dual channel monitor/trip systems, associated process system sensors, and annunciators. The RPS is designed to initiate a reactor scram to:

- Preserve the integrity of fuel cladding.
- Preserve the integrity of the reactor coolant pressure boundary (RCPB).
- Minimize the energy released during a loss-of-coolant accident (LOCA).

Additional information may be found in Unit 1 FSAR Section 7.2 and Unit 2 FSAR Section 7.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C71-01 – Reactivity Control. The RPS is the primary defense against all transients that lead to conditions that could damage the reactor. It is designed to initiate a reactor scram to preserve the integrity of fuel cladding and the RCPB, and minimize energy released during a LOCA.

C71-02 – Power Supply. The RPS system provides electrical power supply for various instrumentation and controls.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.5 REMOTE SHUTDOWN SYSTEM [C82]

System Description

The remote shutdown panels provide controls and indications to safely shut down the reactor for a selected number of components in a selected number of systems in the event the control room becomes uninhabitable.

Unit 1 has six remote shutdown panels located at various locations throughout the reactor building and diesel generator building. Unit 2 has a large remote shutdown panel and a remote shutdown instrument panel on the 130 ft elevation of the reactor building.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C82-01 – Alternate Control Room. The remote reactor shutdown panel provides remote control and indication to bring the reactor to hot and cold shutdown from outside and independent of the main control room (MCR). It provides remote shutdown and supports numerous safety-related functions during an MCR evacuation.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.6 PROCESS RADIATION MONITORING SYSTEM [D11]

System Description

The purpose of the process radiation monitoring system is to provide input into the reactor protection system, primary containment isolation system, and others for system isolation.

There are two types of detectors used in the system, scintillation detectors and gas filled detectors. Scintillation detectors are used because they are the most sensitive and therefore are capable of detecting low levels of radiation. The two types of gas filled detectors are ion chamber and Geiger-Mueller detectors. Ion chamber detectors have the ability to compensate for different types of radiation. Geiger-Mueller detectors are used in systems that require a wide range of gamma detection because they are sensitive to low levels of radiation and can handle a wide range of environmental conditions.

More information on this system can be found in Unit 1 FSAR Section 7.12 and Unit 2 FSAR Section 11.4.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>D11-01 – Main Steam Line Radiation Monitoring.</u> Main steam line radiation monitoring provides indication of abnormal increases in main steam gamma radiation for group 1 isolation.

<u>D11-06 – Primary Containment Gamma Radiation Monitoring (Wide Range).</u> The wide range primary containment radiation monitors are used for measuring gross gamma radiation in the drywell and suppression pool, before, during, and after a LOCA.

<u>D11-12 – Reactor Building Ventilation Radiation Monitoring.</u> This includes the reactor building vent radiation monitoring signals to support the reactor building HVAC indirect radiation release control, secondary containment isolation and standby gas treatment start functions.

<u>D11-13 – Main Control Room Intake Radiation Monitoring</u>. The main control room HVAC air intake is monitored to signal the system to transfer to pressurization mode upon abnormal radiation conditions.

<u>D11-14 – Refueling Floor Ventilation Radiation Monitoring.</u> This includes the refueling floor ventilation radiation monitoring signals to support the reactor building HVAC indirect radiation release control, secondary containment isolation and standby gas treatment start functions.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.7 HEAT TRACE SYSTEM [G13]

System Description

The purpose of the heat trace system is to maintain piping, instrumentation, and equipment in working order during below freezing temperatures. A primary function is to maintain the sodium pentaborate solution in the standby liquid control system at a temperature high enough to prevent precipitation and solidification of the solution.

Standby liquid control storage tank temperature is maintained by adjusting the storage tank heater-indicating controller to maintain temperature between 65 °F and 75 °F to prevent precipitation of the sodium pentaborate from solution. Thermostat controlled heat tracing is run along the pump suction piping to maintain suction piping solution temperature. A temperature versus concentration curve is monitored to ensure that a 10 °F margin will be maintained above saturation temperature.

Additional information may be found in Unit 2 FSAR paragraph 4.2.3.4.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

G13-01 – Freeze Protection. Freeze Protection maintains piping, instrumentation, and equipment in working order during below freezing temperatures. This function also includes the heat tracing function of the standby liquid control boron control required for anticipated transient without scram compliance.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.8 MAIN CONTROL ROOM PANELS SYSTEM [H11]

System Description

The purpose of the main control boards is to provide display, recording, and alarm to enable plant operators to monitor and control the equipment necessary for normal operations and transient/accident mitigation.

The actual controls for each system are included in this system.

Additional information may be found in Unit 1 FSAR Section 7.16 and Unit 2 FSAR Section 3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

H11-01 – Operator Information and Control. The main control boards provide display, recording and alarm to enable plant operators to monitor and control the equipment necessary for normal operations and transient/accident mitigation. The actual controls for each system are included in this function.

Component Groups Requiring an Aging Management Review

Table 2.5.8-1 Components Supporting Electrical Panels, Racks & Cabinets [H11] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Electrical Panels, Racks, and Cabinets	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

2.5.9 IN-PLANT AUXILIARY CONTROL PANELS SYSTEM [H21]

System Description

The purpose of the auxiliary control panels is to provide system information and control to allow operators to operate equipment from outside the main control room (MCR) in the reactor building, turbine building, and other auxiliary buildings.

The actual controls for each system are included in specific functions for the respective system.

Additional information may be found in Unit 1 FSAR Section 7.16 and Unit 2 FSAR Section 3.10.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

H21-01 – Equipment Support and Integrity. The auxiliary control boards provide support for essential equipment. The actual controls for each system and are included in the specific functions for the respective system.

H21-02 – Operator Information and Control. In-plant auxiliary control panels provide system information and control to allow operators to operate equipment from outside the MCR in the reactor building, turbine building, and other auxiliary buildings.

Component Groups Requiring an Aging Management Review

Table 2.5.9-1 Components Supporting Instrument Racks, Panels, & Enclosures [H21] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Instrument Racks, Panels, and Enclosures	Structural Support; Nonsafety Related Structural Support	Carbon Steel

2.5.10 PLANT AC ELECTRICAL SYSTEM [R20]

System Description

The entire auxiliary power distribution system, station service, and emergency service systems consisting of both 1E and Non-1E systems, distribute power to all ac auxiliaries required to startup, operate, and shut down the plant. None of the plant's AC electrical system above 4 kV is in scope.

The emergency service portion Class 1E distributes power to all loads essential to plant safety and normal plant operation ensuring power is available to perform a safe plant shutdown.

The auxiliary power distribution system distributes power to all auxiliaries necessary for normal plant operation.

The station auxiliary ac power system is divided into two portions: one for normal Non-Class 1E service and one for emergency Class 1E service. The emergency service portion distributes ac power required to shut down the reactor, maintain the shutdown condition, and operate all safety-related equipment necessary to mitigate the consequences of major accident conditions. The entire station auxiliary ac power system, both normal and emergency service portions, distributes power to all ac auxiliaries required to start up, operate, and shut down the plant.

Additional information may be found in Unit 1 FSAR Sections 8.3 and 8.7 and Unit 2 FSAR subsection 8.3.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R20-01 – 1E AC Electrical Supply. The 1E ac electrical plant supply provides essential plant equipment.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.11 DC ELECTRICAL SYSTEM [R42]

System Description

The purpose of the dc distribution system is to provide reliable power from a rectified ac source (battery charger) with a battery backup to supply dc loads, control power, logic power, and inverters for all operational modes.

The battery system provides an uninterruptible source of power to normal Non-Class 1E and emergency Class 1E loads such as motors, circuit breaker controls, operation of logic and control relays, emergency lighting, etc. The emergency power is required to safely shutdown the reactor, maintain the reactor in a shutdown condition, and operate all auxiliaries necessary for plant safety under all plant operational modes.

The dc electrical system includes the following:

- 125/250 V station battery system — Class 1E
- 125 V diesel generator battery system — Class 1E
- 125 V cooling tower battery system — Non-Class 1E
- 24/48 V instrumentation battery system — Non-Class 1E
- Battery for 120/240 V vital ac system — Non-Class 1E

Additional information may be found in Unit 1 FSAR Section 8.5 and Unit 2 FSAR subsection 8.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R42-01 – Plant 1E dc Electrical Supply. The dc electrical system provides reliable power to the 125/250 VDC plant dc electrical system and dc metering and relaying.

R42-02 – EDG 1E dc Electrical Supply. The EDG dc electrical system provides reliable power to the 125 VDC EDG electrical system and dc metering and relaying.

R42-05 – Diesel Fire Pump dc Supply. The diesel fire pump dc electrical system provides the necessary starting current for the diesels and the control power for the diesel fire pumps.

R42-07 – Appendix "R" Emergency Lighting. Emergency lights are used to illuminate entrances/exit ways and safety-related equipment in case of a loss of offsite power/power failure.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.12 PLANT COMMUNICATIONS SYSTEM [R51]

System Description

The purpose of the plant communications system is to allow key personnel to communicate information about plant conditions and other pertinent information.

The intrasite communication system consists of a public address system; a private, dial telephone system; and a two-way radio communication system provided for paging and communication. The public address system which consists of handsets, amplifiers, loudspeakers, multitone generator, and associated equipment provides convenient, effective paging, and private conversational service. The private, automatic exchange dial telephone system is an electronic system of modular design utilizing stored program control and time division switching. A separate, two-way radio communication is provided to permit communication with mobile units and base stations within the range of the plant.

Additional information may be found in Unit 1 FSAR Section 10.15 and Unit 2 FSAR subsection 9.5.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R51-01 – Personnel Communication. Personnel communication provides reliable communication via the page system, the intraplant telephone system, sound powered phones, public address system, and private dial telephones.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.13 POWER TRANSFORMERS SYSTEM [S11]

System Description

The inscope components for this system are the CD transformers. The function of these transformers is to provide power to 600V busses C or D from 4160V bus F during station blackout.

The transformers operate by dropping the voltage from 4160 volts to 600 volts.

Additional information may be found in Unit 1 FSAR Section 8.3 and Unit 2 FSAR Section 8.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

S11-02 – Emergency Diesel Generator 1B AC Supply. The CD transformers provide a path between 4160 volt bus F and 600-volt busses C or D during station blackout conditions.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.14 EMERGENCY RESPONSE FACILITIES SYSTEM [X75]

System Description

The purpose of the emergency response facilities is to help the plant operators, shift technical advisors, supervisory personnel, and the NRC in rapidly assessing the plant safety status during normal, transient, and accident conditions.

The NRC-emergency response data system (NRC-ERDS) is the response to the ERDS Rule published in 10 CFR 50 in 1991. It is used during an Alert emergency classification or higher to transmit certain data to the NRC operations center in Rockville, Maryland. The X75 system includes the safety parameter display system (SPDS), the technical support center (TSC) HVAC system, and the ERDS.

For additional information see Unit 1 FSAR Section 7.21 and Unit 2 FSAR Section 7.9.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

X75-01 – Class 1E Signal Isolation. Historical and real-time data involve circuits for which Class 1E cabling must meet separation criteria. These systems could provide erroneous or misleading data to operators in response to an accident if failures occurred in the associated equipment.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.15 PLANTWIDE SCOPING AND SCREENING RESULTS – ELECTRICAL AND INSTRUMENTATION AND CONTROLS

This section presents the results of the screening process for electrical components and commodities. As described in Section 2.1.4 of Scoping Methodology, the list of electrical components subject to an AMR is determined on a plantwide basis by compiling a list of all electrical component types installed in the plant, then applying the scoping and screening criteria in the Rule to determine those component types subject to an AMR. The resulting list is an encompassing list of component types, not individual components. For example, cable is listed as a component type. Individual circuits are not evaluated to determine whether they are in scope. The list of component types subject to an aging management review has been further reduced by application of the scoping criteria to the component types which meet the screening criteria. These criteria are found in 10 CFR 54.4(a). Any component type which does not meet the scoping criteria in this section on a generic basis does not require an aging management review. The comprehensive list of electrical component types is included in Table 2.1-1.

2.5.15.1 Electrical Components Which Require an Aging Management Review

After applying the scoping and screening criteria of Section 2.1.2 and 2.1.4 to the comprehensive list of electrical component types in use at Plant Hatch (see Table 2.1-1), the following component types were found to meet the scoping and screening criteria, and thus, require an aging management review.

Table 2.5.15-1 Components Supporting Plantwide Electrical Intended Functions and Their Component Functions

In-Scope Component	Component Function	Material
Cable* (Inside Containment)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Tinned and Bare Copper
Cable (Outside Containment)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Tinned and Bare Copper
Electrical Connectors, Splices, Terminal Blocks*	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper
Electrical Penetration** Assemblies (See Section 4)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Painted Steel Stainless Steel
Nelson Frames*	Fission Product Barrier Fire Protection	Various Polymers Galvanized and Painted Steel
Phase Bussing*	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper

* No aging effects requiring management

** All electrical penetration assemblies are the subject of a TLAA in Section 4.

2.6 GENERAL REFERENCES

1. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants, The License Renewal Rule."

2. NEI 95-10, Revision 0, "Industry Guideline on Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," March 1996.

3. 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," 56 FR 31324, July 10, 1991.

4. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear power Plants, "60 FR 22491, May 8, 1995.

5. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants, "56 FR 64976, December 13, 1991.

6. 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."

7. "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," Regulatory Guide 1.154.

Section 3

AGING MANAGEMENT REVIEW RESULTS

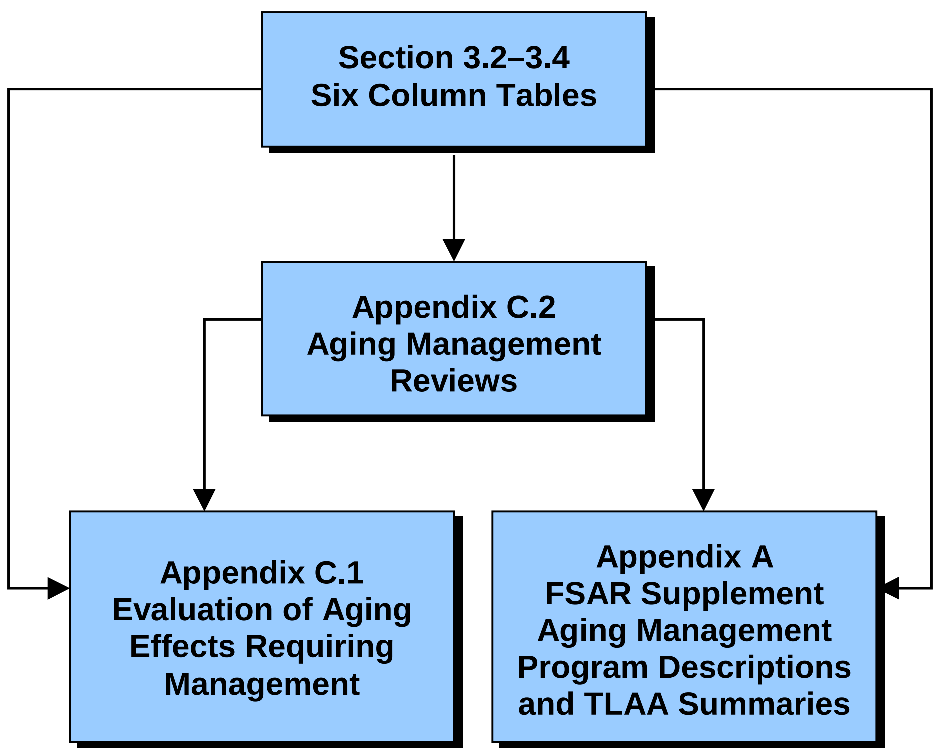
CONTENTS

3.0 AGING MANAGEMENT REVIEW RESULTS

Aging Management Review Information Layout

The relationship between the various elements of the application, as relates to the aging management reviews, is presented by the block diagram on Figure 3.0-1. The application has been arranged so that all review begins with the six-column tables in sections 3.2 through 3.4. These tables present an overview of the aging management review results. Each line item in a table represents a component group subject to an aging management review. The appendix C.2 aging management review section associated with each line item directs the reviewer to the aging management review summary. The aging effects requiring management are listed in the tables with direction to the related appendix C.1 section where the aging effects are evaluated. Credited programs and activities are identified in the tables with direction to the related appendix A program descriptions. However, details of how the credited activities manage the aging effects, in terms of program attributes, are provided in the applicable appendix C.2 section.

Figure 3.0-1 Aging Management Review Process Map



Plant-wide scoping results are presented in section 2.2. The component types subject to aging management review are identified and listed, pursuant to the requirement in 10 CFR 54.21(a)(1), on a system-by-system basis, grouped by discipline, in sections 2.3 through 2.5.

This section presents the results of the aging management reviews performed to support the application. Sections 3.2 through 3.4 present in a tabular format the component types subject to aging management review, the aging effects requiring management, and the programs credited to manage the aging effects. The tables are arranged to be generally consistent with the presentation suggested in the NRC Standard Application Format, and parallel the three-column tables that present the scoping and screening results in sections 2.3 through 2.5.

Consolidation of Component Groups into Commodity Groups

The component types listed in the tables in sections 2.3 through 2.5 were grouped according to the methodology described in section 2.1, based on similar component types, materials, and environments. Additional consolidation of component groups into groups called commodity groups was accomplished prior to performing aging management reviews. The following discussion, while not required by the rule, is provided as information to assist in the review of the Plant Hatch application for a renewed operating license.

Figure 3.0-2 illustrates the process of consolidating component groups into commodity groups. First, as discussed in section 2.1, systems, structures, and functions were identified and evaluated. Each in-scope function in Figure 3.0-2 represents an intended function.

The line in Figure 3.0-2 labeled "Components and Component Types Subject to AMR" illustrates the process of identifying and grouping components that support each intended function. Membership in a component group is based on the component type, its materials of construction, and its internal and external environments, as applicable.

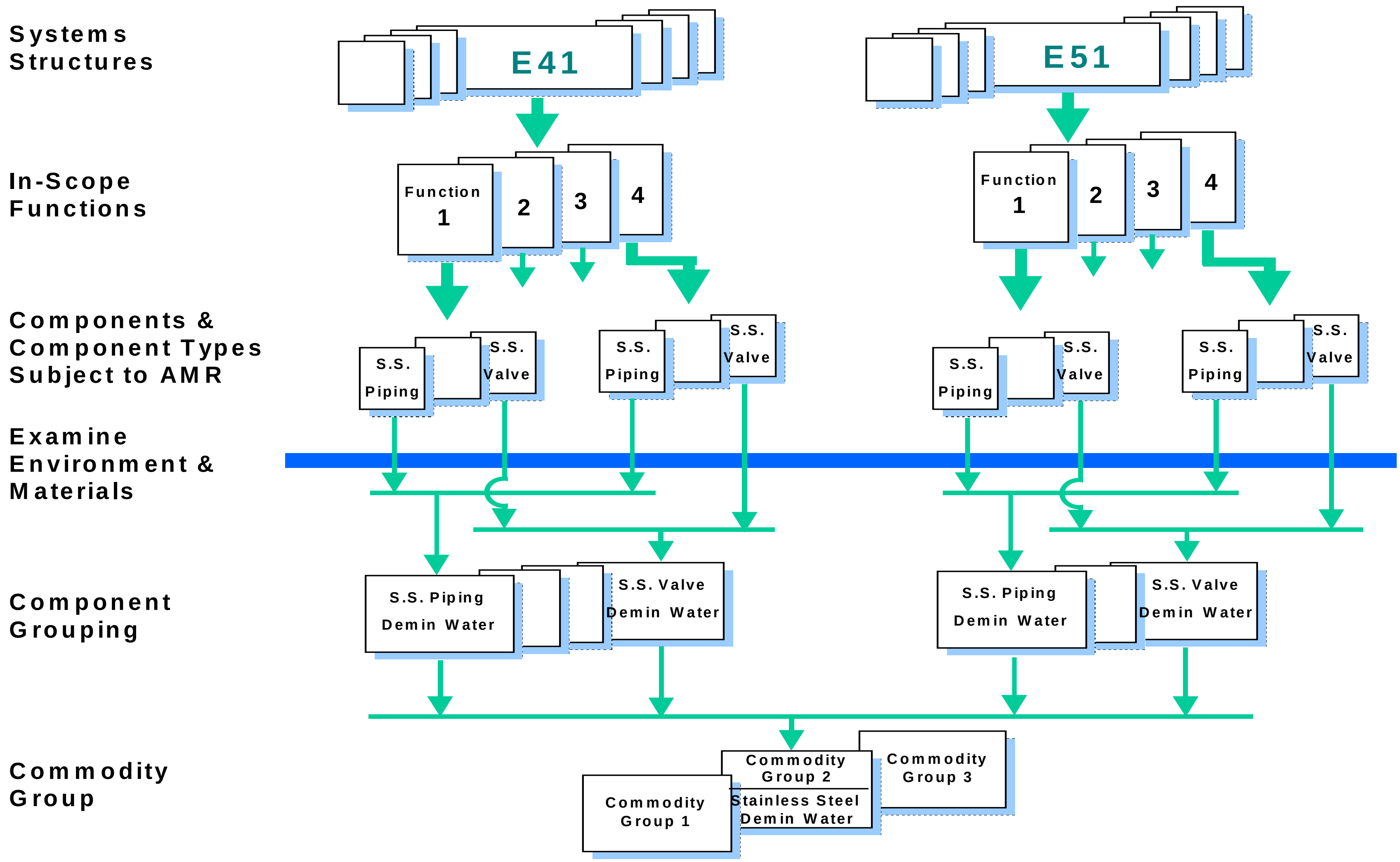
Figure 3.0-2 depicts the further consolidation of component groups across systems or structures. This consolidation of groupings can occur because a number of intended function evaluation boundaries envelope similar components in terms of their materials and environments. For example, the high pressure coolant injection and the reactor core isolation cooling systems at Plant Hatch have similar environments and were constructed from similar materials. Thus, for purposes of aging management review, a component group in an intended function evaluation boundary containing components of the high pressure coolant injection system would be like the same component group in a related intended function evaluation boundary associated with the reactor core isolation cooling system.

Finally, Figure 3.0-2 illustrates the further grouping of these component groups with other component groups having similar materials and environments. For example, stainless steel piping and stainless steel valves with the same internal and external environments can be grouped together into a commodity group. The aging management review summaries in appendix C.2 were performed on the final set of consolidated component groups. These groupings are called commodity groups.

Aging Effects Determination in the Application

Section C.1 of appendix C presents a systematic approach to identification, categorization, and evaluation of plant environments and materials. This systematic assessment evaluated a set of aging effects drawn from an extensive review of industry literature that represents the collective experience of the U.S. nuclear power industry. Each combination of plant environment and component material was assessed, and aging effects were demonstrated as requiring aging management or not requiring aging management in the context of 10 CFR 54.21(a)(3). The complete assessment for each environment/material combination is

Figure 3.0-2 Commodity Group Construction Process



contained in supporting documentation and is not provided in the application. The discussion in appendix C.1 presents those environment/material combinations for which the assessment concluded that aging management is required for one or more aging effects. In general, aging effects not requiring management for an environment/material combination are not presented in the application. Plant Hatch-specific operating experience was examined for each commodity group in appendix C.2, in part, to identify whether other aging effects specific to Plant Hatch should also be addressed. The results of the Hatch-specific operating experience review was incorporated into the aging effects determination presented in section C.1.

Aging Management Reviews

Section C.2 of appendix C presents summaries of the aging management reviews performed on the commodity groups that represent the set of component types subject to aging management review as specified in 10 CFR 54.21(a)(1). The component types were previously listed in sections 2.3 through 2.5. Each C.2 subsection contains the following headings and information:

1. **Descriptive Title for AMR Summary -** The subsection title is generally descriptive of the materials and environment that define a commodity group. For example, "Aging Management Review for Non-Class 1 Stainless Steel Components Within the Demineralized Water Environment" describes stainless steel components that are exposed to demineralized water. A brief description of the commodity group and a list of the associated component types included within the commodity group evaluation is provided.
2. **Systems -**This subheading serves as a placeholder for listing the principal systems with components belonging to the commodity group, and provides a reference back to the application section that identifies the intended functions associated with the commodity group. Figure 3.0-2 illustrates how component types supporting various intended functions are rolled up into the commodity groups. Note that component types with system numbers other than those listed for a particular aging management review summary may be included due to the cross-system establishment of intended function evaluation boundaries.
3. **Aging Effects Requiring Management** - A list of aging effects requiring management, along with the associated aging mechanisms applicable to the commodity group is presented. These aging effects and associated mechanisms were derived from reviews of textbook information, NRC correspondence, industry guidelines, industry reports relating to aging management, and operating experience (see the below discussion on operating experience). Section C.1 of Appendix C provides additional information on these aging effects and associated aging mechanisms. Links to the applicable C.1 information are also provided.
4. **Aging Management Programs -** Once the set of aging effects requiring management was identified for a particular commodity group, a list of aging management programs credited for managing aging of structures or components within the commodity group was produced. This list was compiled by examining the aspects of current programs in plant procedures and program documents. The list includes any new programs or activities to be credited for managing the aging effects. This list also provides links to the applicable Appendix A program descriptions.

5. **Demonstration of Aging Management** - The remainder of each C.2 subsection constitutes the demonstration that the effects of aging are adequately managed during the renewal term. This is accomplished by three complementary sections:

   - For each identified aging effect requiring management, a subsection title descriptive of the aging effect and a brief discussion are provided to present how specific features of applicable aging management programs and activities serve to manage age related degradation of structures and components within the commodity group under evaluation.

     These aging management programs and activities are evaluated to determine if they are applicable to the specific structures or components under evaluation and contain acceptance criteria against which the need for corrective actions will be evaluated. Additionally, aging management objectives including mitigation, detection, and correction of age related degradation are discussed. These text discussions present how aging management programs exhibit the attributes of an effective aging management program in the aging management program assessment tables.

     The broader program descriptions for the activities credited are found in appendix A. The combination of information in the appendix C.2 evaluations and appendix A provides the complete description of the programs to manage aging in the renewal term.

   - The results of a review of operating experience is provided at the conclusion of each aging management review summary or, where applicable, at the end of each environmental evaluation. Operating experience is utilized to verify that all aging effects requiring management were identified by textbook information and industry guidance, and to asses the overall adequacy and effectiveness of current aging management programs credited with managing age related degradation. What follows is a discussion of the methodology employed to produce a comprehensive survey of applicable operating experience:

     Industry experience was collected from resources such as NRC generic letters, bulletins and information notices, GE service information letters, INPO significant operating event reports and topical information from various industry working groups. Plant-specific information was derived through plant walk downs, interviews and records searches.

     Southern Company mechanical, electrical and civil engineers conducted several plant walk downs to gain first hand knowledge of the material condition of the accessible portions of Plant Hatch systems, structures and components. These walk downs were purposefully conducted in advance of personnel interviews and records searches to gain an unbiased view of the material condition of the plant.

     After the plant walk downs, site and corporate interviews were conducted in order to understand the overall maintenance history of SSCs within the scope of license renewal. Coupled with the other components of the AMR process, this effort provided insights as to where the dominant areas of concern might be.

     Having gained information from the plant walk downs and interviews with site and corporate engineers, a large condition reporting database was then searched. This database of more than 37,000 records represented approximately 5 years of plant history, covering the period 1995 through 1999. These searches were conducted using smart-search techniques to provide reasonable assurance that potentially age related problems reported in the database were found. Follow up investigations and interviews were then conducted when the search results indicated reports of potentially age related degradation.

- Finally, aging management program assessment tables present how the various programs credited serve to manage aging of structures or components. These tables list 10 attributes of an effective aging management program in the left column. The right column shows what combination of activities is being credited as satisfying the attribute.

Appendix C.2 is presented in present tense, except for discussions of operating experience which are, of course, past tense. Any specific commitments not part of a program or activity credited in Appendix A are presented in future tense. Appendix A describes existing programs and activities in present tense and enhancements to existing programs or activities and new programs or activities in future tense.

Results

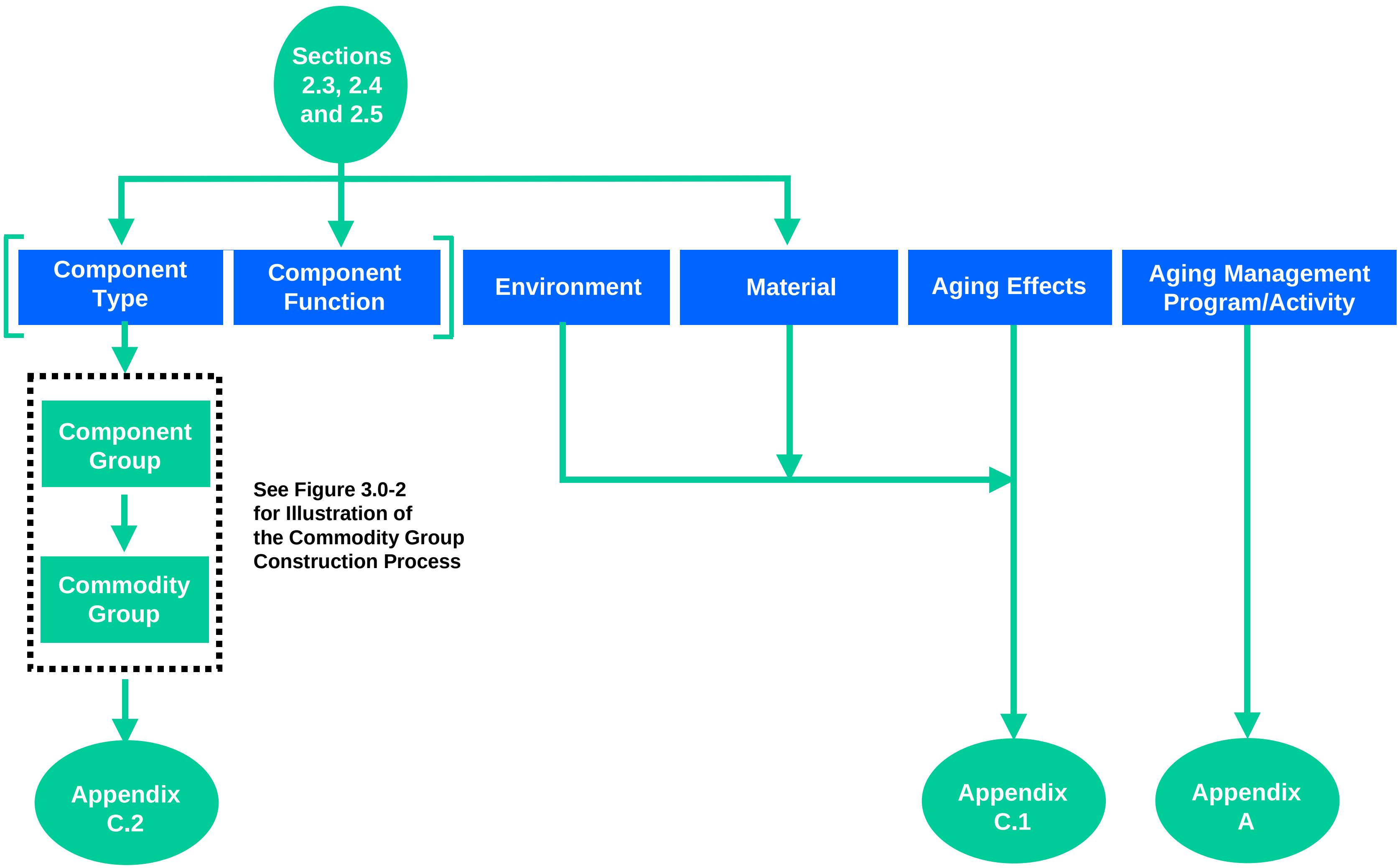
The results of the aging management reviews are presented in sections 3.2 through 3.4 in tabular form. A table is provided for each system or structure with at least one function within the scope of license renewal. These tables provide the following items for each system or structure:

- A component group with a reference to the applicable appendix C.2 aging management review summary for the commodity group in which each component group is evaluated.
- The component function(s) for each component group.
- The environments for each component group.
- The materials of construction for each component group.
- The aging effects requiring management for the component group, with a reference to the applicable C.1 section that discusses the aging effects.
- The programs credited for managing the aging effects, with a reference to the applicable appendix A program descriptions.

It must be noted that condition monitoring programs, such as one time inspections or the ISI Program, utilize representative sample populations with emphasis on the locations most susceptible to age-related degradation. Therefore, although these programs may not provide for specific inspection of the component group under consideration, they are judged to bound or otherwise provide pertinent inspection data concerning common aging effects within component groups having similar materials and environments (and in some cases more limiting conditions) and thereby comprise a portion of the aging management demonstration for the component group under consideration. For example, while the ISI Program does not specifically perform visual inspections of stainless steel piping for pitting and crevice corrosion, it does provide for periodic VT-1 visual inspections of large bore valves. These visual examinations would detect pitting or crevice corrosion in the valves and may be applied to the piping since the environmental conditions and material susceptibilities that allow for the possibility of crevice corrosion or pitting are present in both component groups. In this case, the ISI Program is credited to monitor pitting and crevice corrosion with all applicable stainless steel components, even though only stainless steel valve bodies are inspected. A similar situation occurs concerning the FAC Program. This program provides for volumetric examinations of piping to determine the amount of degradation due to flow accelerated corrosion. While this program does not specifically examine valve bodies for flow accelerated corrosion, valves are included within the mathematical models used to select inspection points. However due to the greater wall thickness values associated with valves, these components are at much lower risk of failure due to FAC and are not generally considered for inspection. In this case, volumetric inspection of the piping is judged to bound any age-related degradation within the valve bodies.

The relationship of the summary information presented in the six-column tables in section 3-2 through 3-4 with the detailed information in the various sections of the application is depicted in Figure 3.0-3.

Figure 3.0-3 Correlation of 6-column Tables to Sections of the Application



3.1 COMMON AGING MANAGEMENT PROGRAMS

See appendix A for the Common Aging Management Programs.

3.2 MECHANICAL SYSTEMS

The following tables provide the mechanical component types that are subject to an aging management review. The aging management for external surfaces is covered in section C.2.4.1. Throughout the tables, cracking is listed as an aging effect where no aging management program is specified. In these cases, cracking is managed by a TLAA. These are also covered in section C.2. No provisions have been made in these summary tables to address these items, since the external surface environments are applicable across systems.

3.2.1 REACTOR

Table 3.2.1-1 Aging Effects Requiring Management for Components Reactor Assembly System [B11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Appurtenances / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Nickel Based Alloy Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Attachments and Connecting Welds / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Carbon Steel Low Alloy Steel Nickel Based Alloy Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Closure Studs / C.2.1.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Low Alloy Steel	Cracking	Boiling Water Reactor Vessel Internals Program Reactor Pressure Vessel Monitoring Program Component Cyclic or Transient Limit Program
Control Rod Drive / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel	Cracking	Inservice Inspection Program Reactor Water Chemistry Control
Core Spray Internal Piping / C.2.1.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel Program Inservice Inspection Program Reactor Water Chemistry Control

Table 3.2.1-1 Aging Effects Requiring Management for Components Reactor Assembly System [B11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Core Spray Sparger / C.2.1.1.2	Pressure Boundary Flow Distribution	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel and Internals Program Inservice Inspection Program Reactor Water Chemistry Control
CRD Housing and CR Guide Tubes / C.2.1.1.2	Structural Support	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Dry Tube Weld to Guide Tube /C.2.1.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Cracking	Inservice Inspection Program Reactor Water Chemistry Control
Jet Pump Assemblies / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel Cast Austenitic Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Nozzles /C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Low Alloy Steel	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Penetrations / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Nickel Based Alloy Stainless Steel	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control
Safe Ends / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Stainless Steel Low Alloy Steel Carbon Steel Nickel Based Alloy	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program

Table 3.2.1-1 Aging Effects Requiring Management for Components Reactor Assembly System [B11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Shell and Closure Heads / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Low Alloy Steel	Loss of Fracture Toughness	Reactor Pressure Vessel Monitoring Program Component Cyclic or Transient Limit Program
Shroud / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel and Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Shroud Supports / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel Nickel Based Alloy Low Alloy Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Thermal Sleeves / C.2.1.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel Nickel Based Alloy	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Top Guide / C.2.1.1.2	Structural Support	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.1.1.6 (Class 1)	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload	Torque Activities Inservice Inspection Program
Bolting / C.2.2.10.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Crack Growth Monitor / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Flow Nozzle / C.2.1.1.3 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Galvanic Susceptibility Inspections Component Cyclic or Transient Limit Program Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Piping / C.2.2.1.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections Flow Accelerated Corrosion Program
Piping / C.2.2.1.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.2.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.3.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Piping / C.2.2.3.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Piping / C.2.1.1.3 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Galvanic Susceptibility Inspections Component Cyclic or Transient Limit Program Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Piping / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Piping / C.2.2.9.1 (Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Inservice Inspection Program Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Restricting Orifice / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Component Cyclic or Transient Limit Program Inservice Inspection Program Treated Water Systems Piping Inspections
Thermowell/ C.2.2.9.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Thermowell / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.9.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Inservice Inspection Program Passive Component Inspection Activities

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.1.1.3 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Galvanic Susceptibility Inspections Component Cyclic or Transient Limit Program Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Valve Bodies / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Valve Bodies / C.2.1.1.5 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Cast Austenitic Stainless Steel	Loss of Material Cracking Loss of Fracture Toughness	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Valve Bodies / C.2.2.9.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies/ C.2.2.2.2 (non-Class 1)	Pressure Boundary Fission Product Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections

3.2.2 REACTOR COOLANT SYSTEMS

Table 3.2.2-1 Aging Effects Requiring Management for Components Supporting Reactor Recirculation System [B31] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting/ C.2.1.1.6 (Class 1)	Fission Product Barrier, Pressure Boundary	Containment Atmosphere	Carbon Steel	Loss of Preload Loss of Material Cracking	Inservice Inspection Program Torque Activities
Flow Nozzle/ C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Piping / C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Pump Casings and Cover/ C.2.1.1.5 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Cast Austenitic Stainless Steel	Loss of Material Cracking Loss of Fracture Toughness	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Thermowell/ C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections

Table 3.2.2-1 Aging Effects Requiring Management for Components Supporting Reactor Recirculation System [B31] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.1.1.5 (Class 1)	Fission Product Barrier Pressure Boundary	Reactor Water	Cast Austenitic Stainless Steel	Loss of Material Cracking Loss of Fracture Toughness	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Valve Bodies/ C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections

3.2.3 ENGINEERED SAFETY FEATURES (ESF) SYSTEMS

Table 3.2.3-1 Aging Effects Requiring Management for Components Supporting Standby Liquid Control System [C41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Piping / C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Pump Accumulators/ C.2.2.4.1	Pressure Boundary	Borated Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Protective Coatings Program
Pump Casing / C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Tanks/ C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Thermowell/ C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies/ C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Conductivity Element / C.2.2.3.2	Fission Product Barrier, Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Heat Exchanger Channel Assembly / C.2.2.11.1	Pressure Boundary	Raw Water	Carbon Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Heat Exchanger Impingement Plate / C.2.2.11.1	Shelter/ Protection	Torus Water	Stainless Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Suppression Pool Chemistry Control
Heat Exchanger Shell / C.2.2.11.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Inservice Inspection Program Suppression Pool Chemistry Control
Heat Exchanger Tube Sheet / C.2.2.11.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	Suppression Pool Chemistry Control RHR Heat Exchanger Augmented Inspection and Testing Program

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Heat Exchanger Tube Sheet / C.2.2.11.1	Pressure Boundary	Raw Water	Stainless Steel Clad Carbon Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Heat Exchanger Tubes / C.2.2.11.1	Pressure Boundary Fission Product Barrier, Exchange Heat	Torus Water	Stainless Steel	Cracking Loss of Material Loss of Heat Exchanger Performance	Suppression Pool Chemistry Control RHR Heat Exchanger Augmented Inspection and Testing Program
Heat Exchanger Tubes/ C.2.2.11.1	Fission Product Barrier, Pressure Boundary Exchange Heat	Raw Water	Stainless Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Piping / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking Loss of Heat Exchanger Performance	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Galvanic Susceptibility Inspections Structural Monitoring Program

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Pump Casings / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Pump Casings - Bowl Assembly/ C.2.2.6.2	Pressure Boundary	Raw Water	Cast Austenitic Stainless Steel	Loss of Material Flow Blockage Cracking Loss of Heat Exchanger Performance	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Pump Discharge Head / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections
Pump Sub Base / C.2.4.1	Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program
Restricting Orifices / C.2.2.3.2	Fission Product Barrier, Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Restricting Orifices / C.2.2.3.2	Fission Product Barrier, Pressure Boundary, Flow Restriction	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Restricting Orifices / C.2.2.6.2	Pressure Boundary, Flow Restriction	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Strainer Bodies / C.2.2.6.1	Debris Protection	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Galvanic Susceptibility Inspections Structural Monitoring Program
Strainers / C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Thermowell / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Tubing / C.2.2.6.3	Pressure Boundary	Raw Water	Copper Alloy	Loss of Material Cracking Flow Blockage	PSW and RHRSW Chemistry Control Program PSW and RHRSW Inspection Program Structural Monitoring Program
Valve Bodies / C.2.2.3.1	Pressure Boundary, Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspection Treated Water Systems Piping Inspection
Valve Bodies/ C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Galvanic Susceptibility Inspections Structural Monitoring Program

Table 3.2.3-3 Aging Effects Requiring Management for Components Supporting Core Spray System [E21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Piping / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Pump Casings / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Restricting Orifice / C.2.2.3.2	Fission Product Barrier, Pressure Boundary, Flow Restriction	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Strainers / C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Valve Bodies / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspection

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary Fission Product Barrier	Inside	Stainless Steel	Loss of Preload	Torque Activities
Flexible Connector / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Dry Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Galvanic Susceptibility Inspections Flow Accelerated Corrosion Program
Piping / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Program Treated Water Systems Piping Inspections
Piping / C.2.2.3.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections
Piping/ C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Pump Baseplate / C.2.4.1	Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program
Pump Casings / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifice / C.2.2.1.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifice / C.2.2.2.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Program Treated Water Systems Piping Inspections
Restricting Orifice / C.2.2.9.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Suction Strainer/ C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Thermowell /C.2.2.3.2	Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Turbine / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections
Valve Bodies / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and CST Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.3.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary Fission Product Barrier	Inside	Stainless Steel	Loss of Preload	Torque Activities
Flexible Connectors / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Galvanic Susceptibility Inspections Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Piping / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.1.2	Pressure Boundary Fission Production Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.3.1	Pressure Boundary Fission Production Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Pump Baseplate / C.2.4.1	Structural Support	Air	Carbon Steel	Loss of Material	Protective Coatings Program
Pump Casing / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifices / C.2.2.2.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifices / C.2.2.9.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Steam Trap / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections Flow Accelerated Corrosion Program
Steam Trap / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Steam Trap / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Steam Trap / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Strainer- Steam Exhaust/ C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Suction Strainer / C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Thermowell / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Thermowell / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Turbine / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.3.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Cast Austenitic Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.3-6 Aging Effects Requiring Management for Components Supporting Standby Gas Treatment System [T46] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Filter Housing / C.2.2.9.4	Fission Product Barrier Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Piping / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.9.3	Fission Product Barrier Pressure Boundary	Air	Copper	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.9.4	Fission Product Barrier Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Rupture Disc / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Thermowell / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Gray Cast Iron	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.3-6 Aging Effects Requiring Management for Components Supporting Standby Gas Treatment System [T46] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.3	Fission Product Barrier Pressure Boundary	Air	Copper Alloy	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.3-7 Aging Effects Requiring Management for Components Supporting Primary Containment Purge and Inerting System [T48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Flex Hose / C.2.2.9.1	Pressure Boundary	Air	Stainless Steel	Cracking	Gas Systems Component Inspections
Nitrogen Tank Jacket / C.2.2.9.1	Structural Support	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.3.1	Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Torus Submerged Components Inspection Program
Piping / C.2.2.3.1	Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Piping / C.2.2.3.2	Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Pressure Buildup Coil / C.2.2.8.2	Pressure Boundary Exchange Heat	Dried Gas	Stainless Steel	Cracking	None Required
Rupture Disc / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Storage Tank / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required

Table 3.2.3-7 Aging Effects Requiring Management for Components Supporting Primary Containment Purge and Inerting System [T48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Thermowell / C.2.2.9.2	Pressure Boundary	Inside	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.3.2	Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Vaporizer / C.2.2.8.2	Pressure Boundary, Exchange Heat	Dried Gas	Stainless Steel	Cracking	None Required

Table 3.2.3-8 Aging Effects Requiring Management for Components Supporting Post LOCA Hydrogen Recombiner System [T49] Intended Functions and Their Component Functions (Unit 2 only)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

3.2.4 AUXILIARY SYSTEMS

Table 3.2.4-1 Aging Effects Requiring Management for Components Supporting Control Rod Drive System [C11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Accumulator / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Accumulator/ C.2.2.8.1	Pressure Boundary Fission Product Barrier	Dried Gas	Carbon Steel	Cracking	None Required
Bolting / C.2.2.10.1 (Non-Class 1)	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Piping / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.8.2	Pressure Boundary Fission Product Barrier	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.4-1 Aging Effects Requiring Management for Components Supporting Reactivity Control System [C11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Rupture Disc / C.2.2.8.2	Pressure Boundary Fission Product Barrier	Dried Gas	Stainless Steel	Cracking	None Required
Valve Bodies / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.8.3	Pressure Boundary Fission Product Barrier	Dried Gas	Copper Alloy	Cracking	None Required
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.3	Pressure Boundary Fission Product Barrier	Air	Copper Alloy	Cracking	None Required

Table 3.2.4-2 Aging Effects Requiring Management for Components Supporting Refueling Platform Equipment Assembly [F15] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts C.2.6.3	Structural support Nonsafety Related Structural Support	Inside	Carbon steel	Loss of material	Protective Coatings Program Overhead Crane and Refueling Platform Inspection
Miscellaneous Steel C.2.6.3	Structural support; Nonsafety Related Structural Support	Inside	Carbon steel	Loss of material	Protective Coatings Program Overhead Crane and Refueling Platform Inspection
Rivets	Structural Support	Inside	Aluminum	None	None Required
Structural Steel C.2.6.3	Structural support	Inside	Carbon steel	Loss of material	Protective Coatings Program Overhead Crane and Refueling Platform Inspection

Table 3.2.4-3 Aging Effects Requiring Management for Components Supporting the Insulation System [L36] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Aluminum Jacket / C.2.4.4.2	Environmental Control	Outside	Aluminum	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program
Insulation / C.2.4.4.1	Environmental Control	Outside	Asbestos, Calcium, Silicate, Fiberglass	Loss of Material Cracking Change in Material Properties	Equipment and Piping Insulation Monitoring Program
Insulation / C.2.4.4.1	Environmental Control	Inside, Outside	Ceramics, Mineral Fiber	Loss of Material Cracking Change in Material Properties	Equipment and Piping Insulation Monitoring Program
Insulation Bolting / C.2.4.4.2	Environmental Control	Outside	Galvanized Steel	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program
Insulation Bolting / C.2.4.4.2	Environmental Control	Outside	Stainless Steel	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program
Stainless Steel Jacket / C.2.4.4.2	Environmental Control	Inside	Stainless Steel	Loss of Material Cracking Change in Material Properties	Equipment and Piping Insulation Monitoring Program
Wire for Insulation / C.2.4.4.2	Environmental Control	Outside	Carbon Steel	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program

Table 3.2.4-4 Aging Effects Requiring Management for Components Supporting Access Doors [L48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.3	Missile Barrier Fission Product Barrier	Inside, Outside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.2.4-5 Aging Effects Requiring Management for Components Supporting Condensate Transfer and Storage System [P11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.2	Pressure Boundary	Outside	Stainless Steel	Loss of Preload	Torque Activities
Piping / C.2.2.2.2	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Tanks / C.2.2.2.3	Pressure Boundary	Demin Water	Aluminum	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Condensate Storage Tank Inspection
Tanks / C.2.2.2.3	Pressure Boundary	Demin Water	Galvanized Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Condensate Storage Tank Inspection
Tanks / C.2.2.2.3	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Condensate Storage Tank Inspection
Valve Bodies / C.2.2.2.2	Pressure Boundary	Demin Water	Cast Austenitic Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspection
Valve Bodies / C.2.2.2.2	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspection

Table 3.2.4-6 Aging Effects Requiring Management for Components Supporting Sampling System [P33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.4-7 Aging Effects Requiring Management for Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Outside, Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Flexible Connector / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Piping / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections
Piping / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Pump Bowl Assembly / C.2.2.6.2	Pressure Boundary	Raw Water	Cast Austenitic Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Pump Discharge Column / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Pump Discharge Head / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program

Table 3.2.4-7 Aging Effects Requiring Management for Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Pump Sub Base / C.2.4.1	Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program
Restricting Orifices / C.2.2.6.2	Pressure Boundary, Flow Restriction	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Sight Glass Body / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Galvanic Corrosion Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Sight Glass Body/ C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer / C.2.2.6.4	Pressure Boundary	Raw Water	Gray Cast Iron	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer Basket / C.2.2.6.2	Debris Protection	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer Basket / C.2.2.6.4	Debris Protection	Raw Water	Gray Cast Iron	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program

Table 3.2.4-7 Aging Effects Requiring Management for Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Thermowell / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program
Thermowell / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program
Valve Bodies / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections
Valve Bodies / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Valve Bodies / C.2.2.6.3	Pressure Boundary	Raw Water	Copper Alloy	Loss of Material Cracking Flow Blockage	PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Venturi / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections

Table 3.2.4-8 Aging Effects Requiring Management for Components Supporting Reactor Building Closed Cooling Water System [P42] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Flexible Connectors / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Flow Element / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Heat Exchanger Shells / C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Piping / C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Piping / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Piping / C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Relief Valve Base / C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Temperature Probe / C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Thermowell / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Valve Bodies / C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Valve Bodies / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection

Table 3.2.4-9 Aging Effects Requiring Management for Components Supporting Instrument Air System [P52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Air Receiver / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Hose / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Piping / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Regulator Pressure / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Tubing/ C.2.2.8.3	Pressure Boundary	Dried Gas	Copper	Cracking	None Required
Valve Bodies / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper Alloy	Cracking	None Required

Table 3.2.4-10 Aging Effects Requiring Management for Components Supporting Primary Containment Chilled Water System [P64] Intended Functions and Their Component Functions (Unit 2 Only)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting/ C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Cap/ C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Piping/ C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Thermowell/ C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies/ C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.4-11 Aging Effects Requiring Management for Components Supporting Drywell Pneumatics System [P70] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Filter Housings / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Filter Housings / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Flanges / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Flexible Hoses / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Piping / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Tubing / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper	Cracking	None Required
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Valve Bodies / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper Alloy	Cracking	None Required

Table 3.2.4-12 Aging Effects Requiring Management for Components Supporting Emergency Diesel Generator System [R43] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Expansion Tank / C.2.2.2.1	Pressure Boundary	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Filter housing / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Flex Hose / C.2.2.2.2	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Flexible Connector/ C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.2.1	Pressure Boundary	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Piping / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.9.4	Pressure Boundary	Air	Galvanized Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Restricting Orifice/ C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Tanks / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.4-12 Aging Effects Requiring Management for Components Supporting Emergency Diesel Generator System [R43] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.2.1	Pressure Boundary	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Valve Bodies / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.3	Pressure Boundary	Wetted Gas	Copper Alloy	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.4-13 Aging Effects Requiring Management for Components Supporting Reactor Building Crane [T31] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.3	Structural Support	Inside	Carbon Steel	Loss of Material	Overhead Crane and Refueling Platform Inspection Protective Coatings Program

Table 3.2.4-14 Aging Effects Requiring Management for Components Supporting Tornado Relief Vent Assemblies [T38] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Screws / C.2.6.3	Structural Support	Inside; Outside	Stainless Steel	None	None Required
Support Frame/ C.2.6.6	Structural Support	Inside; Outside	Aluminum	None	None Required
Tornado Relief Vent Dome/ C.2.6.8	Fission Product Barrier	Inside; Outside	Acrylic (Plexiglas G Cellcast Acrylic Polymer)	Cracking	Structural Monitoring Program

Table 3.2.4-15 Aging Effects Requiring Management for Components Supporting Reactor Building HVAC System [T41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Fission Product Barrier, Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Ductwork / C.2.2.9.4	Fission Product Barrier, Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Flow Element / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking	Gas Systems Component Inspections
Tubing / C.2.2.9.3	Pressure Boundary	Air	Copper Alloy	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.4-16 Aging Effects Requiring Management for Components Supporting Traveling Water Screens / Trash Rack System [W33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Trash Rack / C.2.6.3	Debris Protection	Submerged	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Traveling Screen / C.2.6.3	Debris Protection	Submerged	Carbon Steel Stainless Steel	Loss of Material	Structural Monitoring Program
Traveling Screen / C.2.6.3	Debris Protection	Submerged	Copper Alloy	None	None Required
Valve Bodies / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Galvanic Susceptibility Inspections

Table 3.2.4-17 Aging Effects Requiring Management for Components Supporting Outside Structures HVAC System [X41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Outside	Stainless Steel	Loss of Preload	Torque Activities
Duct Sleeve / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Restricting Orifices / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Tubing / C.2.2.9.3	Pressure Boundary	Air	Copper	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Boltings / C.2.2.10.1	Pressure Boundary	Inside Outside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Fire Doors / C.2.3.4.3	Fire Barrier	Inside	Carbon Steel	Loss of Material	Fire Protection Activities
Fire Doors / C.2.3.4.3	Fire Barrier	Inside	Galvanized Steel Copper Alloy Stainless Steel Aluminum Nonmettalic, Inorganic Gypsum Fibers, Nonasbestos Synthetic Nonmetallic, Organic	None	None Required
Fire Hydrants / C.2.3.1	Pressure Boundary	Raw Water	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Fittings / C.2.3.1	Pressure Boundary	Raw Water Air	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Fittings / C.2.3.3	Pressure Boundary	Air	Copper Alloy Cast Iron	Cracking Loss of Material	Fire Protection Activities
Fusible Material / C.2.3.1	Pressure Boundary	Inside	Nonferrous Metal	Loss of Material Cracking	Fire Protection Activities
Kaowool Hold-Down Straps / C.2.3.4.3	Fire Barrier	Inside	Galvanized Steel	Cracking Change in Material Properties	Fire Protection Activities

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Nozzles / C.2.3.1	Flow Restriction	Air	Copper Alloy	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Nozzles / C.2.3.3	Flow Restriction	Air	Aluminum Copper Alloy	Cracking Loss of Material	Fire Protection Activities
Penetration Seals / C.2.3.4.1	Fire Barrier	Inside; Embedded	Ceramics Carbon Steel Synthetic Fiber Elastomers Concrete	Cracking Change in Material Properties Loss of Material	Fire Protection Activities
Pilot Valves / C.2.3.1	Pressure Boundary	Raw Water	Aluminum	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Pipe Line Strainers / C.2.3.1	Pressure Boundary	Air	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Piping / C.2.3.1	Pressure Boundary	Raw Water Air	Carbon Steel Aluminum Galvanized Steel Copper Alloy Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Piping / C.2.3.2	Pressure Boundary	Fuel Oil	Carbon Steel Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing Fire Protection Activities
Piping / C.2.3.3	Pressure Boundary	Air Carbon Dioxide Dried Gas	Carbon Steel Galvanized Steel	Cracking Loss of Material	Fire Protection Activities

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Pump Casings / C.2.3.1	Pressure Boundary	Raw Water	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Restricting Orifices / C.2.3.1	Pressure Boundary, Flow Restriction	Raw Water Air	Stainless Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Sprinkler Head Bulbs / C.2.3.1	Pressure Boundary	Inside	Ceramics	Cracking	Fire Protection Activities
Sprinkler Head Links / C.2.3.1	Pressure Boundary	Inside	Copper	Loss of Material Cracking	Fire Protection Activities
Sprinkler Heads / C.2.3.1	Flow Direction, Pressure Boundary, Flow Restriction	Raw Water Air	Stainless Steel Copper Alloy Carbon Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Strainer Basket / C.2.3.1	Pressure Boundary	Air Raw Water	Stainless Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Strainers / C.2.3.1	Pressure Boundary	Air Raw Water	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Tank / C.2.3.1	Pressure Boundary	Air	Carbon Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Tank / C.2.3.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities Protective Coatings Program
Tank / C.2.3.2	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing Fire Protection Activities

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Tank / C.2.3.3	Pressure Boundary	Carbon Dioxide, Dried Gas	Carbon Steel	Cracking Loss of Material	Fire Protection Activities
Tank Insulation / C.2.3.3	Environmental Control	Inside	Organic	Cracking Change in Material Properties	Fire Protection Activities
Tubing / C.2.3.2	Pressure Boundary	Fuel Oil	Copper Alloy	Loss of Material Cracking	Fire Protection Activities Diesel Fuel Oil Testing
Tubing Fittings / C.2.3.1	Pressure Boundary	Fuel Oil Raw Water	Copper Alloy Cast Iron Copper	Loss of Material Cracking	Fire Protection Activities
Valve Bodies / C.2.3.1	Pressure Boundary	Raw Water Air	Carbon Steel Cast Iron Copper Alloy	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Valves Bodies / C.2.3.2	Pressure Boundary	Fuel Oil	Copper Alloy Cast Iron	Loss of Material Cracking	Diesel Fuel Oil Testing Fire Protection Activities
Valves Bodies / C.2.3.3	Pressure Boundary	Carbon Dioxide Dried Gas Air	Carbon Steel Copper Alloy	Cracking Loss of Material	Fire Protection Activities

Table 3.2.4-19 Aging Effects Requiring Management for Components Supporting Fuel Oil System [Y52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Discharge Head / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Flex Hose / C.2.2.7.2	Pressure Boundary	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Manway Shell / C.2.2.9.1	Shelter/ Protection	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Piping / C.2.2.7.2	Pressure Boundary	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Piping / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspection Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Pump / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Strainer Basket / C.2.2.7.2	Shelter/ Protection	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Tank / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Cracking Loss of Material	Diesel Fuel Oil Testing

Table 3.2.4-19 Aging Effects Requiring Management for Components Supporting Fuel Oil System [Y52] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Valve Bodies / C.2.2.7.2	Pressure Boundary	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Valve Bodies / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.4-20 Aging Effects Requiring Management for Components Supporting Control Building HVAC System [Z41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Accumulator / C.2.2.9.1 Air Valve	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections
Accumulator Piping / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Accumulator Tanks / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Duct Gasket / C.2.6.7	Pressure Boundary	Air; Inside	Fibers, Nonasbestos Synthetic; Elastomers, Other	Material Property Changes and Cracking	Passive Component Inspection Activities Gas System Component Inspections
Duct Heater / C.2.2.9.4	Pressure Boundary	Air	Aluminum	Loss of Material	Gas Systems Component Inspections
Duct Silencer / C.2.2.9.4	Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Ductwork / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Ductwork / C.2.2.9.4	Pressure Boundary	Outside	Galvanized Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Ductwork Flex Connector / C.2.6.7	Pressure Boundary	Air; Inside	Fibers, Non-Asbestos Synthetic; Elastomers, Other	Material Property Changes and Cracking	Passive Component Inspections Activities Gas Systems Component Inspections
Filter Housing / C.2.2.9.4	Pressure Boundary	Air	Galvanized Steel	Cracking	None Required

Table 3.2.4-20 Aging Effects Requiring Management for Components Supporting Control Building HVAC System [Z41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Instrument Piping / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Instrument Piping / C.2.2.9.3	Pressure Boundary	Air	Copper Alloy	Loss of Material Cracking	Gas Systems Component Inspections
Louver / C.2.2.9.1	Pressure Boundary	Outside	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Radiation Element / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Restricting Orifice / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Thermowell / C.2.2.9.2	Pressure Boundary	Inside	Stainless Steel	Cracking	None Required
Tubing / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper	Cracking	None Required
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper Alloy	Cracking	None Required
Valve Bodies / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

3.2.5 STEAM AND POWER CONVERSION

Table 3.2.5-1 Aging Effects Requiring Management for Components Supporting Electro-Hydraulic Control System [N32] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.5-2 Aging Effects Requiring Management for Components Supporting Main Condenser System [N61] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Condenser Shell / C.2.2.1.1	Fission Product Barrier Pressure Boundary	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Preheater / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Preheater / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifices/ C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Strainer / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections

Table 3.2.5-2 Aging Effects Requiring Management for Components Supporting Main Condenser System [N61] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Thermowell / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.1	Pressure Boundary	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections

3.3 CIVIL/STRUCTURAL

The following tables provide the civil/structural component types that are subject to an aging management review.

3.3.1 CIVIL/STRUCTURAL COMPONENTS

Table 3.3.1-1 Aging Effects Requiring Management for Components Supporting Piping Specialties [L35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Hangers and Supports for ASME Class I Piping / C.2.6.4	Structural Support	Containment Atmosphere; Inside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Hangers and Supports for ASME Class I Piping / C.2.6.4	Structural Support	Containment Atmosphere; Inside	Stainless Steel	None	None Required
Hangers and Supports for Non ASME Class I Piping, Tubing, and Ducts / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Inside; Outside; Submerged	Carbon Steel Galvanized Steel Stainless Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Tube Trays and Covers / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Stainless Steel	None	None Required

Table 3.3.1-2 Aging Effects Requiring Management for Components Supporting Cable Trays and Supports [R33] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Cable Trays and supports / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Inside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Cable Trays and supports / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Inside	Aluminum	None	None Required

Table 3.3.1-3 Aging Effects Requiring Management for Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts / C.2.6.2	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Embedded; Inside Torus Water	Carbon Steel Galvanized Steel Stainless Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Suppression Pool Chemistry Control
Blind Flange* / C.2.2.3.1	Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control
Containment Isolation Valves* / C.2.2.2.2	Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Containment Isolation Valves* / C.2.2.3.1	Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Containment Isolation Valves* / C.2.2.3.1	Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Containment Isolation Valves* / C.2.2.6.2	Fission Product Barrier	Raw Water	Carbon Steel	Loss of Material Cracking	Passive Component Inspection Activities
Containment Isolation Valves* / C.2.2.9.1	Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Containment Isolation Valves* / C.2.2.9.2	Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspection
Containment Penetrations (Mechanical only) / C.2.6.2	Fission Product Barrier	Containment Atmosphere; Embedded; Inside	Carbon Steel Stainless Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Primary Containment Leakage Rate Testing Program

Table 3.3.1-3 Aging Effects Requiring Management for Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions (Continued)

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Miscellaneous Steel / C.2.6.2	Structural Support; Radiation Shielding; Pipe Whip Restraint; Nonsafety Related Structural Support	Containment Atmosphere; Embedded; Inside; High Humidity; Torus Water	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Suppression Pool Chemistry Control
Piping* / C.2.2.2.2	Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping* / C.2.2.3.1	Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Piping* / C.2.6.2	Fission Product Barrier	Raw Water	Carbon Steel	Loss of Material Cracking	Passive Component Inspection Activities
Piping* / C.2.2.9.1	Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Piping* / C.2.2.9.2	Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material	Gas Systems Component Inspection
Reinforced Concrete / C.2.6.1	Structural Support; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding	Inside; Containment Atmosphere	Concrete Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Steel Bellows (Inside Vent Pipe) C.2.6.2	Pressure Boundary; Fission Product Barrier	Containment Atmosphere; Inside	Carbon Steel Stainless Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Primary Containment Leakage Rate Testing Program

Table 3.3.1-3 Aging Effects Requiring Management for Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions (Continued)

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel / C.2.6.2	Structural Support; Shelter/Protection; Pressure Boundary; Radiation Shielding; Nonsafety Related Structural Support; HE/ME Shielding; Missile Barrier; Pipe Whip Restraint; Fission Product Barrier; Exchange Heat	Containment Atmosphere; Inside; Torus Water; Embedded	Carbon Steel Stainless Steel	Loss of Material Cracking	Protective Coatings Program Primary Containment Leakage Rate Testing Program Inservice Inspection Program Suppression Pool Chemistry Control Component Cyclic or Transient Limit Program
Tubing* / C.2.2.9.2	Fission Product Barrier; Pressure Boundary	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections
Vent Pipe, Vent Header, Downcomers / C.2.6.2	Pressure Boundary Fission Product Barrier	Containment Atmosphere; High Humidity; Inside; Torus Water	Carbon Steel	Loss of Material Cracking	Protective Coatings Program Inservice Inspection Program Primary Containment Leakage Rate Testing Program Component Cyclic or Transient Limit Program Suppression Pool Chemistry Control

* Piping and valve bodies include components from systems P51, P21, T23, G51, G11, D11, and C51. These are all included in function T23-01, Torus/Drywell.

Table 3.3.1-4 Aging Effects Requiring Management for Components Supporting Fuel Storage [T24] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts / C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Anchors and Bolts / C.2.6.5	Structural Support	Inside; Demin Water; Embedded	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control
Miscellaneous Steel / C.2.6.3	Structural Support ; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Miscellaneous Steel / C.2.6.5	Fission Product Barrier	Demin Water ; Embedded; Inside	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control
Reinforced Concrete / C.2.6.1	Structural Support; Shelter/Protection	Inside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete / C.2.6.1	Structural Support; Nonsafety Related Structural Support	Inside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Seismic restraints for spent fuel storage racks / C.2.6.6	Structural Support	Inside; Demin Water	Aluminum	Loss of Material	Fuel Pool Chemistry Control
Storage Racks/ C.2.6.6	Structural Support; Nonsafety Related Structural Support	Inside	Aluminum	None	None Required
Structural Steel / C.2.6.5	Structural Support; Shelter/Protection; Fission Product Barrier	Demin Water; Inside	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control

Table 3.3.1-5 Aging Effects Requiring Management for Components Supporting Reactor Building [T29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts / C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Blowout Panels / C.2.6.6	Structural Support; Fission Product Barrier	Inside	Aluminum	None	None Required
Miscellaneous Steel / C.2.6.3	Structural Support; HE/ME Shielding; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Miscellaneous Steel / C.2.6.3	Structural Support; HE/ME Shielding; Nonsafety Related Structural Support	Inside; Outside	Stainless Steel	None	None Required
Panel Joint Seals and Sealants / C.2.6.7	Shelter/Protection; Fission Product Barrier	Inside; Outside	Elastomers; Nonmetallic, Inorganic	Material Property Changes and Cracking Loss of Adhesion	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete C.2.6.1	Structural Support; Fire Barrier; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding; Nonsafety Related Structural Support	Inside; Outside	Concrete Masonry Block Carbon Steel	Loss of Material Cracking	Structural Monitoring Program Protective Coatings Program
Structural Steel C.2.6.3	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Inside; Outside; Submerged	Carbon Steel Galvanized Steel Stainless Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-6 Aging Effects Requiring Management for Components Supporting Drywell Penetrations [T52] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.2	Fission Product Barrier	Containment Atmosphere; Embedded; Inside	Carbon Steel	Loss of Material	Protective Coatings Program Primary Containment Leakage Rate Testing Program Inservice Inspection Program

Table 3.3.1-7 Aging Effects Requiring Management for Components Supporting Reactor Building Penetrations [T54] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.3	Fission Product Barrier	Embedded; Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program

Table 3.3.1-8 Aging Effects Requiring Management for Components Supporting Turbine Building [U29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside; Outside; Wetting Other Than Humidity	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Radiation Shielding; Nonsafety Related Structural Support	Buried; Inside; Outside	Concrete Masonry Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-9 Aging Effects Requiring Management for Components Supporting Intake Structure [W35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside; Outside; High Humidity; Wetting Other Than Humidity	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Miscellaneous Steel C.2.6.3	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Embedded; High Humidity; Inside; Outside; Wetting Other Than Humidity; Submerged	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete C.2.6.1	Structural Support; Shelter/Protection; Flood Barrier; Missile Barrier; Nonsafety Related Structural Support	Buried; Submerged; Inside; Outside; High Humidity; Wetting Other Than Humidity	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel C.2.6.3	Structural Support; Shelter/Protection; Missile Barrier; Flow Direction; Nonsafety Related Structural Support	Embedded; Outside; Inside; High Humidity; Wetting Other Than Humidity	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-10 Aging Effects Requiring Management for Components Supporting Yard Structures [Y29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Cover Plates – Pull Boxes/ C.2.6.6	Shelter/Protection; Flood Barrier	Inside; Outside	Aluminum	None	None Required
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-11 Aging Effects Requiring Management for Components Supporting Main Stack [Y32] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Outside	Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside; Outside	Stainless Steel; Copper Alloy (Bronze)	None	None Required
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Outside	Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Galvanized Steel	None	None Required
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Fission Product Barrier; Nonsafety Related Structural Support; Radiation Shielding	Inside; Outside	Concrete Carbon Steel	Loss of Material Cracking	Structural Monitoring Program Protective Coatings Program
Structural Steel / C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Galvanized Steel	None	None Required

Table 3.3.1-12 Aging Effects Requiring Management for Components Supporting Emergency Diesel Generator Building [Y39] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Nonsafety Related Structural Support; Missile Barrier	Inside; Outside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-13 Aging Effects Requiring Management for Components Supporting Control Building [Z29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Blowout Panels / C.2.6.6	Structural Support; Fission Product Barrier	Inside	Aluminum	None	None Required
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Nonsafety Related Structural Support; Missile Barrier	Inside / Outside	Concrete Carbon Steel	Loss of Material Cracking	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

3.4 ELECTRICAL

The following tables provide the electrical component types which are subject to an aging management review. These component types are not associated with one particular system, but could be used in any in-scope system, and are evaluated on a plant-wide basis for the determination of aging effects requiring management. The determination of aging effects requiring management is presented in section C.1.3. Electrical penetrations meet the criteria for components which require an aging management review; however, these components are covered under a TLAA which is discussed in section 4.

3.4.1 ELECTRICAL COMPONENTS

Table 3.4.1-1 Aging Effects Requiring Management for Electrical Components (Plant-Wide)

Electrical Component	Component Function	Environment	Material	Aging Effects	Aging Management Program/Activity
Cable (Outside Containment) / C.2.5.4	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Submerged; Inside: Outside	Various Polymers Tinned and Bare Copper	Change in Insulation Resistance	Wetted Cable Activities
Cable (Inside Containment) / C.2.5.5	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside	Various Polymers Tinned and Bare Copper	None	None
Electrical Connectors Splices, Terminal Blocks / C.2.5.3	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside/Outside	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper	None	None
Electrical Penetration Assemblies (Section 4, Figure 4.4-5)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside	Various Polymers Painted Steel Stainless Steel	None	None Penetration assemblies are covered by an EQ TLAA.

Table 3.4.1-1 Aging Effects Requiring Management for Electrical Components (Plant-Wide) (Continued)

Electrical Component	Component Function	Environment	Material	Aging Effects	Aging Management Program/Activity
Phase Bussing/ C.2.5.1	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper	None	None
Nelson Frames/ C.2.5.2	Fission Product Barrier Fire Protection	Inside	Various Polymers Galvanized and Painted Steel	None	None

Table 3.4.1-2 Aging Effects Requiring Management for Components Supporting Electrical Panels, Racks & Cabinets [H11] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Electrical panels, racks and cabinets/ C.2.6.4	Structural Support; Shelter/Protection Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program

Table 3.4.1-3 Aging Effects Requiring Management for Components Supporting Instrument Racks, Panels, & Enclosures [H21] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Instrument racks, panels and enclosures/ C.2.6.4	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program

4.1 INTRODUCTION

Southern Nuclear has performed a detailed review of design analyses and calculations for Plant Hatch, pursuant to 10 CFR 54.21(c)(1), to determine which analyses meet the criteria of 10 CFR 54.3. Analyses and calculations that meet the criteria of 10 CFR 54.3 contain time-limited or age related assumptions. The review included analyses performed by Southern Company, the architect engineer, and the nuclear steam supply system vendor. Independently, Southern Nuclear performed a review of the Current Licensing Basis (CLB) for time-limited or age-related statements that met the criteria or 10 CFR 54.3. These two separate reviews provided assurance that analyses meeting the rule requirements would be properly identified and dispositioned. The review yielded analyses in several categories, summarized in Table 4.1.1-1.

4.1.1 IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES

Time-Limited Aging Analyses (TLAAs) are defined in 10 CFR 54.3 as analyses that meet six criteria. The regulation, as quoted below, requires the licensee to provide an evaluation of the analyses that meet all of the criteria.

Time-limited aging analyses are those licensee calculations and analyses that:

- Involve systems, structures, and components within the scope of license renewal, as delineated in Section 54.4(a);
- Consider the effects of aging;
- Involve time-limited assumptions defined by the current operating term, for example, 40 years;
- Were determined to be relevant by the licensee in making a safety determination;
- 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 Section 54.4(b); and
- Are contained or incorporated by reference in the CLB.

10 CFR 54.21(c) requires licensees to include a list of time-limited aging analyses in the application. The licensee must demonstrate that either:

- the analyses remain valid for the extended license term;
- the analyses have been acceptably projected to the end of the extended term; or
- programs manage the effects of aging associated with the analyses.

This section addresses the analyses that were reviewed by Southern Nuclear and the issues discovered in the process. For those analyses that did meet the six criteria listed above, this section presents a detailed discussion of the analyses.

4.1.1.1 Procedure

Southern Nuclear created a procedure to evaluate specific analyses for the six TLAA criteria. The review focused on those calculations performed by Bechtel Power Corporation (the previous architect engineer), the Southern Company Services, Inc., (SCS) Engineering organization (the current architect engineer), and the General Electric Company (GE) for the Nuclear Steam Supply System equipment scope.

To identify the scope of calculations to review, Southern Nuclear compiled a complete list from the Plant Hatch Design Record Management System for Bechtel and SCS calculations. General Electric was contracted to identify possible TLAAs for specific systems and components within GE's scope of supply. However, Southern Nuclear principally relied upon the CLB review to identify the TLAAs in GE's scope. Southern Nuclear focused the review of its calculations on the time-limited nature of TLAAs. Calculations were first screened for Criterion 3 with specific emphasis on assumptions or design elements related to the current operating term of 40 years.

The second step was to evaluate the remaining analyses for the other five criteria, beginning with a determination of whether the calculation addressed the design of systems, structures, and components that were in the scope of license renewal. Both active and passive components were addressed in the review for TLAAs.

4.1.1.2 Identification of Exemptions

The License Renewal Rule requires a list be provided of "plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation."

This list has been compiled through a search of docketed correspondence, the operating licenses, and the FSAR. All exemptions in effect were identified and listed and Bechtel SERCH was used, as well as in-house databases. Each exemption in effect was then evaluated to determine if it involved a TLAA as defined in 10 CFR 54.3.

Evaluation of the exemptions in effect for Plant Hatch revealed that one item was similar to an exemption request containing a TLAA that will need to be updated for license renewal. However, this item is not a 10 CFR 50.12 exemption. Rather, this item is a technical alternative (as defined in 10 CFR 50.55a(a)(3)(i)) to the requirements to inspect circumferential welds on the reactor pressure vessel. The relief request is described in the letter dated December 2, 1998, from H. L. Sumner to the NRC document control desk (Ref. 1). This TLAA and its demonstration are discussed in greater detail in section 4.6.3 of this application.

Table 4.1.1-1 Time-Limited Aging Analyses

Time-Limited Aging Analyses	
1.	Piping stress analyses that consider thermal fatigue cycles defined by the life of the plant. The results of the evaluation for 60 years of operation are provided in section 4.2.
2.	Fatigue/stress analyses for the torus structure and nozzle connections. The results of the evaluation for 60 years of operation are provided in section 4.2.
3.	Piping wall thickness calculations that develop acceptable as-measured criteria for pipe walls based upon an anticipated corrosion rate that, in turn, is based upon the life of the plant. The results of the evaluation for 60 years of operation are provided in section 4.3.
4.	Calculation of the corrosion allowance assumed for the reactor vessel. The results of the evaluation for 60 years of operation are provided in section 4.3.
5.	Environmental equipment qualification calculations that qualify electrical components for 40 years. The results of the evaluation for 60 years of operation are provided in section 4.4.
6.	A containment penetration structural analysis that assumes a number of pressurization cycles over the 40-year life of the plant. The results of the evaluation for 60 years of operation are provided in section 4.5.
7.	Calculation of the reference temperature for nil-ductility for critical core region vessel materials accounting for radiation embrittlement (as required by 10 CFR 50 Appendix G). The results of the evaluation for 60 years of operation are provided in section 4.6.
8.	Calculation of the end-of-life equivalent Charpy Upper-Shelf Energy margin (as required by 10 CFR 50 Appendix G) due to the extended operating term. The results of the evaluation for 60 years of operation are provided in section 4.6.
9.	Analyses performed to demonstrate the acceptability of a technical alternative to the Code requirement for inspection of reactor pressure vessel circumferential welds. The results of the evaluation for 60 years of operation are provided in section 4.6.
10.	Change in the anticipated operating cycles of the main steam isolation valves (MSIVs) from the number of cycles assumed for 40 years in the Plant Hatch FSAR. The results of the evaluation for 60 years of operation are provided in section 4.7.

4.2 PIPE STRESS TIME-LIMITED AGING ANALYSES

Thermal fatigue is addressed in the majority of the pipe stress analyses that Southern Nuclear reviewed. The welds between the components and the piping were addressed in the piping analyses; therefore, this section focuses on the piping stress analyses treatment of thermal fatigue. The treatment of thermal fatigue is different, depending on the code requirements for Class 1 and Non-Class 1 piping. Therefore, the two types of piping will be discussed separately. Non-Class 1 components include ASME Section III Classes 2 and 3, B31.7 Classes 2 and 3, and B31.1, power piping and tubing.

4.2.1 CURRENT LICENSING BASES FOR FATIGUE CYCLES AT PLANT HATCH

For both Class 1 and Non-Class 1 analyses, Southern Nuclear reviewed the Bechtel and SCS calculations for assumptions pertaining to the number of thermal cycles. For Class 1 analyses, the Code requires a detailed treatment of the number of thermal cycles the piping will experience. The Plant Hatch Unit 1 FSAR, section A.3, and Plant Hatch Unit 2 FSAR, section 3.9, provide a listing of the number of thermal transients Class 1 piping is assumed to experience over the current license term. The Plant Hatch Unit 2 FSAR also contains statements in sections 3.9 and 6.3 (Ref. 2&3) that address the number of thermal cycles that the Class 2 and 3 piping will experience. The Unit 2 FSAR states that these systems will have fewer than 7,000 thermal cycles over the current license term. Since the calculation method for pipe stress analysis is the same for Non-Class 1 piping on both units, the thermal cycle assumption applies to both units.

The fatigue evaluation for Non-Class 1 piping and tubing was not explicitly performed but is accounted for by the stress range reduction factor, *f*, for cyclic conditions. The design codes provide the values of *f* based on the number of equivalent full-temperature cycles. Therefore, the assumed number (7,000) is important because it allows a stress range reduction factor of 1.0 to be used in the allowable stress equations for piping analysis. This assumption is carried over to the nonsafety-related piping for both units because the analysis method is the same. Therefore, a time-limited, age-related assumption is inherent in the piping analyses.

4.2.2 EVALUATION OF CLASS 1 COMPONENTS

SCS, Bechtel, GE, and various subcontractors performed Class 1 component stress analyses for Plant Hatch. SCS reviewed these analyses and identified TLAAs from the stress reports along with relevant time-dependent calculations.

The ASME Code Editions of record for Class 1 component design for Plant Hatch are detailed in Table 4.2.2-1.

The applicable codes identified in Table 4.2.2-1 require an evaluation of the predicted fatigue cumulative usage factor (CUF) for the Class 1 components. The calculation of the predicted CUF includes inherent assumptions as to the number of transient events over the original 40-year license term. The ASME Code requires that the Class 1 components have an initial design predicted CUF less than or equal to 1.0. Therefore, when the extended license term is considered, NRC requires that Class 1 component locations with a predicted CUF of greater than 1.0 require special consideration.

For Plant Hatch, the CUF carries further importance in that Southern Nuclear also used the predicted CUF as a screening criterion to establish locations to be monitored, inspection locations, and the locations of assumed pipe breaks for accident analysis. Southern Nuclear has followed the guidance of NRC Branch Technical Position MEB 3-1, as expressed in Regulatory Guide 1.46 (Ref. 4), with respect to determining break locations for accident analysis.

Because of explicit commitment to Branch Technical Position MEB 3-1 in the Plant Hatch licensing basis, Southern Nuclear has considered the CUF ≤ 0.1 criterion, and will continue to consider the criterion, when stress calculations are revised as a result of plant design modifications or changes in operating parameters. Because the criterion represents a screening rather than a design constraint, there is no time-limited aspect to the criterion. Thus, it does not represent a time limited aging analysis as used in license renewal.

Southern Nuclear has addressed the Class 1 fatigue TLAAs through an aging management program {demonstration of Criterion (iii) of 10 CFR 54.21 (c) (1)}. This program monitors the CUF of specific bounding locations for Class 1 components at Plant Hatch. The CUF-monitoring program is a complement to other aging management program elements, such as the inservice inspection program. The CUF-monitoring program was implemented in two phases.

The first phase, developed by GE in 1985, included limiting locations in the reactor pressure vessel (RPV). As a result of this phase of the program, Plant Hatch monitors CUF for four components in the RPV. These components are the RPV closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles. These components are monitored for both units (References 5 & 6). The decision criteria for selecting the RPV locations were based on the highest calculated CUFs from the design basis (e.g., fatigue-sensitive locations).

For the second phase of the CUF monitoring program, Southern Nuclear expanded the CUF monitoring program to include Class 1 piping. Conservative equations (Ref. 7) were developed into which actual plant transient counts could be input to estimate the CUF. The equations were developed to monitor the CUF for the limiting locations in each Class 1 piping system where the 40-year predicted CUF exceeded 0.1 in the original analysis. The choice of the 0.1 CUF decision criterion was not related to the MEB 3-1 commitment. This decision value includes sufficient margin, together with explicit fatigue design conservatisms, to account for potential reactor water environmental effects in the selection process.

Much of the conservatism in the design basis calculational process is due to design basis transient definitions. The equations for both the RPV and the Class 1 piping locations are conservatively based on such transient definitions. Based on the several EPRI license renewal fatigue studies, Southern Nuclear concludes that the fatigue impact of conservative design basis transient definitions by themselves overwhelms any potential impact of reactor water environmental effects. Therefore, the use of design basis transient severity in the CUF equations is another conservatism that more than compensates for potential reactor water environmental effects.

Based on the decision criteria and the conservative formulae, the effects of the reactor water environment have been adequately incorporated into the Plant Hatch fatigue management program. Therefore, the "thermal fatigue" aging mechanism identified throughout this application is considered to also encompass any relevant reactor water environmental effects (GSI 190 – Fatigue Evaluation of Metal Components for 60 years).

The equations for the RPV locations have been used to provide current CUF estimates for the past 15 years. To develop a baseline for the Class 1 piping locations, Southern Nuclear evaluated the current CUF based upon actual operating history for both Hatch units to date. The actual operating history was used to project a 60-year CUF for each monitored location. All monitored locations are projected to have a CUF less than 1.0 after 60 years of operation. Southern Nuclear will use the GE-developed equations to continue to monitor CUF for the RPV locations. Southern Nuclear will also use the newer equations to monitor CUF for the Class 1 piping locations. These Class 1 piping locations are as follows:

- Unit 1 RPV equalizer piping;
- Unit 1 core spray piping (for replaced piping outside of the reactor vessel);
- Unit 1 standby liquid control piping;
- Unit 1 feedwater, high pressure coolant injection (HPCI), reactor core isolation cooling (RCIC), reactor water cleanup (RWCU) system piping;
- Unit 1 main steam piping (loop B);
- Unit 2 main steam piping (loop D);
- Unit 2 residual heat removal (RHR) suction piping;
- Unit 2 feedwater piping; and
- Unit 2 steam condensate drainage piping.

Based upon the conclusions of the analysis, Southern Nuclear has expanded the fatigue-monitoring program to include these additional Class 1 locations (see “Component Cyclic or Transient Limit Program,” appendix A.1.12). Specific events and significant temperature changes will be recorded throughout the remaining current term and through the extended license term. The CUF equations will be updated, and the CUF tracked to measure the CUF against an acceptance criteria of less than or equal to 1.0. In this way, Southern Nuclear manages the TLAA by an Aging Management Program {demonstration of Criterion (iii) of 10 CFR 54.21(c)(1)}.

Table 4.2.2-1 ASME Codes Applicable for Class 1 Piping

Unit	Design Code	Year
1	B31.7, CLASS 1	1969
2	SECTION III, NB	1971

4.2.3 EVALUATION OF TIME-LIMITED AGING ANALYSES FOR NON-CLASS 1 PIPING

The subject components of this review are Non-Class 1 piping components. Non-Class 1 components include ASME Section III Classes 2 and 3, B31.7 Classes 2 and 3, and B31.1 power piping and tubing. This review treats the tubing and other piping components, such as fittings, etc., as piping components because of their pressure boundary function. That is, unless otherwise stated, the use of the term “piping” in the following discussion collectively applies to piping, tubing, and other piping components.

After identification, the TLAAs were evaluated to provide assurance that the piping components addressed by these analyses could perform their intended function(s) during the period of their extended operation of 60 years.

Plant Hatch Non-Class 1 piping was originally designed to the requirements of the ASME Code(s) identified in Table 4.2.3-1 as applicable to the system being analyzed.

To evaluate the effects of cumulative fatigue damage, the total number of full temperature thermal cycles of Hatch Non-Class 1 piping and tubing systems were evaluated using highly conservative assumptions. The thermal events and the associated number of cycles were established from a review of the FSAR, operations manual, and operating history. It was estimated that the Non-Class 1 piping and tubing systems would encounter substantially less than the current design basis of 7,000 and 14,000 cycles, respectively, during 60 years of operation. The basis of the stress reduction factors used for the piping and tubing systems in the original design is, therefore, not affected by operating the plant in the extended operating period of 60 years. Hence, for license renewal, the subject TLAAs, which address thermal fatigue, remain valid for the period of extended operation {demonstration of Criterion (i) of 10 CFR 54.21 (c) (1)}. Table 4.2.3-2 lists the aging management reviews described in appendix C that utilize this TLAA.

Table 4.2.3-1 ASME Codes Applicable to Non-Class 1 Piping

Unit	Design Code	Year
1	B31.1	1967
1	B31.7 CLASS 2, 3	1969
2	SECTION III, NC, ND	1971 through 1971 Addenda
2	B31.1	1967 through 1971 Addenda

Table 4.2.3-2 Aging Management Reviews that Utilize the Thermal Fatigue TLAA

Section Number	Components Reviewed
C.2.2.1.1	Carbon Steel Components in Reactor Water Environments
C.2.2.1.2	Stainless Steel Components in Reactor Water Environments
C.2.2.2.1	Carbon Steel Components in Demineralized Water Environments
C.2.2.2.2	Stainless Steel Components in Demineralized Water Environments
C.2.2.2.3	Condensate Storage Tanks and Components in Demineralized Water Environment
C.2.2.3.1	Carbon Steel Components in Suppression Pool Water Environments
C.2.2.3.2	Stainless Steel Components in Suppression Pool Water Environments
C.2.2.4.1	Carbon Steel Components in Borated Water Environments
C.2.2.4.2	Stainless Steel Components in Borated Water Environments
C.2.2.5.1	Carbon Steel Components in Closed Cooling Water Environments
C.2.2.5.2	Stainless Steel Components in Closed Cooling Water Environments
C.2.2.5.3	Copper Components in Closed Cooling Water Environments
C.2.2.6.1	Carbon Steel Components in River Water Environments
C.2.2.6.2	Stainless Steel Components in River Water Environments
C.2.2.6.3	Copper Components in River Water Environments
C.2.2.6.4	Gray Cast Iron Components in River Water Environments
C.2.2.7.1	Carbon Steel Components in Fuel Oil Environments
C.2.2.7.2	Stainless Steel Components in Fuel Oil Environments
C.2.2.8.1	Carbon Steel Components in Dry Compressed Gas Environments
C.2.2.8.2	Stainless Steel Components in Dry Compressed Gas Environments
C.2.2.8.3	Copper Components in Dry Compressed Gas Environments
C.2.2.9.1	Carbon Steel Components in Humid and Wetted Gas Environments
C.2.2.9.2	Stainless Steel Components in Humid and Wetted Gas Environments
C.2.2.9.3	Copper Components in Humid and Wetted Gas Environments
C.2.2.9.4	Galvanized Steel in Humid and Wetted Gas Environments
C.2.3.1	Water Based Fire Suppression System Components
C.2.3.2	Diesel Fuel Oil Supply System Components
C.2.3.3	Compressed Gas Based Fire Suppression System Components
C.2.3.4.1	Carbon Steel Penetration Sleeves in Fire Barriers

4.2.4 EVALUATION OF THE TORUS

The calculation review for TLAAs identified several calculations that met the six criteria and that addressed fatigue (both dynamic and thermal) of the torus structure. Southern Nuclear reviewed these calculations and determined that a new analysis was necessary to address fatigue in the torus for the extended license term. The analysis (Ref. 8) required an extensive and detailed review of pressure and thermal transients for the torus. Plant operating records and the Plant Unique Analysis Reports, prepared for the Mark I Containment Long Term Program, were consulted in the review. From the review, Southern Nuclear determined that the critical event leading to fatigue of the torus was the lifting of one or more main steam system safety relief valves (SRV).

The analysis concluded that the CUF could be monitored by tracking the number of SRV lifts. The analysis developed formulae for calculating the CUF at any given time during the current and extended license terms based upon the number of SRV lifts. Southern Nuclear has chosen to manage the fatigue of the torus by tracking the SRV lifts and evaluating the fatigue usage for the torus during the current and extended license term {demonstration through Criterion (iii) of 10 CFR 54.21(c)(i)}. This aging management program, “Component Cyclic or Transient Limit Program,” is discussed in appendix A.1.12.

4.3 CORROSION ALLOWANCE

An allowance for corrosion was made in determining the appropriate thickness for pressure retaining components in the design of Plant Hatch. Only those analyses containing an assumption of a corrosion allowance that also tied the allowance to a 40-year operating life meet 10 CFR 54.3 Criterion 3. In the review of the Plant Hatch analyses, two scopes of supply are important; the equipment designed and supplied by Bechtel and the equipment designed and supplied by GE.

4.3.1 BECHTEL POWER CORPORATION SCOPE OF SUPPLY

The assumption of a corrosion allowance appears in calculations that confirm pressure rating of piping and components. The piping specifications for both units of Plant Hatch specify corrosion allowances for types of piping based upon material and environment. In most of the calculations reviewed, the corrosion allowance assumed was not tied to a 40-year life of the component. Additionally, corrosion rates were not identified (with specific exceptions discussed). Many of the calculations used standard values from Table A104.2 of ASME B31.1. Once a required minimum wall thickness was calculated, the design often chose the next thicker component size (e.g., the next higher pipe schedule). For these reasons, calculations covering components in the Bechtel scope of supply generally do not meet the definition of a TLAA.

There is a subset of analyses that are the exception to the above paragraph. In the course of evaluating the residual heat removal service water system piping and the plant service water system piping in accordance with Nuclear Regulatory Commission (NRC) Generic Letters 89-13 and 90-05 (References 9 & 10), Bechtel performed calculations to develop evaluation levels for measurements on the piping. These levels were in part based upon the expected thickness of a pipe and upon the predicted wear of that pipe for the remaining service life. In these analyses, the corrosion allowance from the pipe specification was assumed to be the maximum allowed for the 40-year service life of the piping. The corrosion rate thus defined is used in the calculations to predict the expected pipe thickness and to develop the minimum acceptable as-found thickness of the pipe.

These calculations were instrumental in developing the inspection program for the residual heat removal and primary service water piping, much of which is in-scope for license renewal. The formulae used in the calculations have been retained in the inspection program procedure used at Plant Hatch.

The Plant Service Water and RHR Service Water Piping Inspection Program (A.1.13) uses one of two corrosion rates to predict the minimum acceptable measured pipe wall thickness. The first rate is defined by dividing the specified corrosion allowance by 40 years. The second rate is an observed corrosion rate based upon several measurements of the pipe wall. The greater of the two corrosion rates is used to predict the acceptable minimum wall thickness. The action levels of the procedure are also based, in part, on the corrosion rate determined by the corrosion allowance.

The impact of an extended operating period on the inspection program is minimal. A change to the specification-based corrosion rate would not be conservative and is not necessary. Decreasing the corrosion rate (by dividing the current allowance by 60 rather than 40 years) is not appropriate, because a rate thus calculated would not be conservative for the purposes of establishing screening levels for the piping. Therefore, the calculations are conservative for the extended term and do not require revision.

The Plant Service and RHR Service Water Inspection Program will continue to manage the effects of aging (corrosion) for the extended license term {demonstration through Criteria (i) and (iii) of 10 CFR 54.21 (c) (i)}.

4.3.2 GENERAL ELECTRIC SCOPE OF SUPPLY

In reviewing the documents within the design records database, Southern Nuclear found no GE calculation or analysis that explicitly defined the corrosion allowance as a function of 40 years. Therefore, Southern Nuclear contracted GE to make a further determination within their scope of supply. The GE review developed the following conclusions about the Hatch 1 and 2 stainless steel components, general piping, and the reactor vessel.

For austenitic stainless steel components in the Plant Hatch reactor system, the corrosion allowance was not explicitly calculated using a 40-year assumption. The corrosion rate for stainless steel under BWR conditions is very low, and the corrosion allowance will be adequate through the end of the renewal term.

With respect to the reactor vessel, GE reviewed its internal communications, reports, and open literature to determine the method for calculating the Hatch Units 1 and 2 corrosion allowance. The GE review determined (Ref. 21) that a time-dependent corrosion rate was used and that the corrosion allowance was based upon a 40-year assumption for the service life of the vessel. Since this corrosion allowance was determined to meet all six criteria, the corrosion allowance is a TLAA. GE has evaluated the corrosion allowance for the vessel and has determined that the allowance is adequate for operation through the end of the renewed license term {demonstration through Criterion (ii) of 10 CFR 54.21 (c) (i)}.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

Among the most obvious time-limited aging analyses (TLAAs) are those used in existing aging management programs. One such aging management program is the Hatch EQ Program, in which Class 1E safety-related components are qualified in accordance with the requirements of 10 CFR 50.49.

Southern Nuclear has conducted an initial assessment of the Hatch EQ Program to determine which of the analyses in the program meet the definition of a TLAA. The assessment includes evaluations of the EQ analyses to determine if the components qualified could be extended to 60 years. Southern Nuclear is in the process of updating the actual analyses to reflect these assessments.

Section 4.4 discusses the process Southern Nuclear used to identify the TLAAs within the EQ Program for Plant Hatch and then gives a detailed discussion of the EQ Program. In the discussion of the EQ Program for Plant Hatch, it is important to note that Southern Nuclear has prepared qualification data packages (QDPs) to demonstrate that the equipment defined by 10 CFR 50.49(b) is qualified for service in the normal operating environments and accident environments specified for Units 1 and 2. The QDPs are organized in an EQ Central File.

The organization of section 4.4 is as follows:

Process for Identifying EQ TLAAs

Hatch EQ Program Summary Description

Hatch EQ Program Responsibilities

EQ Process

- Original qualification basis
- EQ master list
- EQ maintenance
- Replacement of EQ equipment
  - Replace the existing equipment with identical equipment.
  - Replace the equipment with different equipment which is currently evaluated under the EQ program.
  - Replace the equipment with different equipment which is not currently evaluated under the EQ program.
  - Reanalyze the qualified life calculation.
- Refurbishment of EQ equipment
- Procurement of EQ equipment
- Plant environmental changes

4.4.1 PROCESS FOR IDENTIFYING EQ TLAAS

For the purposes of identifying TLAAs, Southern Nuclear reviewed the QDPs and the supporting calculations for the six qualifying criteria. The primary sorting criteria in this effort were Criterion 3 (whether the component was qualified for at least 40 years) and Criterion 4 (whether the analysis was relevant in making a safety determination with regard to the component being qualified).

Analyses for those components with qualified lives less than 40 years did not meet Criterion 3.

Each QDP contains Environmental Qualification Report Evaluations (EQREs) and supporting calculations. Southern Nuclear reviewed the EQREs and support calculations for the six criteria. Southern Nuclear determined that some met the definition of a TLAA. More than one demonstration method was applicable for some of the TLAAs because multiple installations of similar equipment were evaluated. All three demonstration methods may apply to certain TLAAs. Of special interest are those TLAAs that indicate that at least some of the evaluated components qualified lives cannot currently be projected to the end of the extended license term. The aging effects for these components are managed by the EQ Program per the requirements of 10 CFR 50.49. For some of the TLAAs, the components are qualified through the end of the period of extended operation, with the exception of specific applications inside containment at higher elevations where the temperatures are known to exceed the 60-year qualified life temperature. Equipment with less than a 60-year qualified life is managed by the EQ program in the same way equipment with qualified lives less than the original 40-year license term is managed.

Some calculations were more general in nature. One general class of calculations, for example, determined the 40-year radiation dose in a given area containing in-scope equipment. The total integrated radiation dose calculations apply to multiple QDPs and enable qualification of components to the end of the extended period of operation.

The rest of the TLAAs are valid for the extended license period with minor qualitative documentation changes.

<u>GSI 168 - Environmental Qualification of Electrical Equipment.</u> Generic Safety Issue 168 was reviewed by Southern Nuclear to identify any generic concerns that may be related to the effects of aging within the scope of the license renewal rule.

With regard to that GSI, Southern Nuclear will continue to manage the effects of aging in accordance with the current licensing basis, as modified as appropriate to address regulatory changes that might evolve through the final resolution of that TLAA.

4.4.2 HATCH ENVIRONMENTAL QUALIFICATION PROGRAM SUMMARY DESCRIPTION

The Nuclear Regulatory Commission (NRC) established nuclear plant EQ requirements in General Criterion 4 of 10 CFR 50 Appendix A and in 10 CFR 50.49, which specifically require that an EQ program be established to demonstrate that certain electrical equipment located in "harsh" plant environments (i.e., those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line breaks (HELBs), and post-LOCA radiation) are qualified to perform their safety function in those harsh environments. The requirements of 10 CFR 50.49 apply to all new and replacement electrical equipment, within the scope of 10 CFR 50.49, purchased after February 22, 1983. The scope of equipment covered by the Hatch EQ program is:

- Safety-related (in accordance with the definition in 10 CFR 50.49(b), consistent with the Plant Hatch CLB) electrical equipment located in a postulated harsh environment that is required to mitigate the consequences of the accident causing the harsh environment, or whose subsequent failure can degrade safety systems or mislead the plant operator.
- Nonsafety-related electrical equipment located in a postulated harsh environment whose failure could prevent a safety function or mislead the plant operator. The impact to emergency operation procedures should be considered in the failure analysis.
- Certain post-accident monitoring equipment located in a postulated harsh environment designated as requiring qualification in the Regulatory Guide 1.97 section of the licensee's response to Supplement 1 of NUREG-0737.

The Hatch EQ program is described in section 7.16 of the Unit 1 FSAR and section 3.11 of the Unit 2 FSAR (References 12 & 13) and is administratively controlled by procedures which define the responsibilities and requirements for implementing the Hatch EQ program to ensure compliance with 10 CFR 50.49.

The Hatch EQ program is currently implemented as described in this summary. Changes in the implementation of the Hatch EQ program as described in this summary are made whenever appropriate by changing the controlling procedure(s). Changes to the procedures for the EQ program are administratively controlled by a procedure which gives instructions for administrative procedures and by the Hatch quality assurance process to ensure continued compliance with 10 CFR 50.49.

The Hatch EQ program consists of activities which are integrated into the overall plant design and modification process, including initial design and modification (e.g., selection and application of equipment), documentation review and approval, maintenance, refurbishment, replacement, and procurement. A summary description of these activities and how they are implemented follows in sections 4.4.3 and 4.4.4.

4.4.3 HATCH EQ PROGRAM RESPONSIBILITIES

Hatch EQ program responsibilities are assigned to several groups within the Southern Company.

- **Southern Nuclear** has among its responsibilities:
  - Providing overall administration of the EQ program
  - Resolving generic EQ issues
  - Providing technical support for EQ related issues
  - Controlling and administering the EQ procedures and qualification documentation (including the EQ Master List)
  - Providing input to the design engineering process
  - Managing qualification testing programs and performing qualification evaluations
  - Maintaining the EQ design basis documentation
  - Providing information to the plant groups to maintain qualification

- **Plant Engineering** has among its responsibilities:
  - Providing information and technical support to plant maintenance, procurement, planning, and other plant groups for EQ-related issues and processes.
  - Ensuring that all EQ mandated activities are addressed and scheduled.
  - Ensuring that the plant modification process addresses EQ requirements, including the type and degree of documentation required.
  - Initiating and monitoring site EQ-related procedure changes.
- **The site maintenance organization with input from the site EQ coordinator** has the responsibility for implementing plant maintenance procedures and ensuring that maintenance personnel are properly trained in and carry out the EQ program maintenance requirements.
- **The site procurement organization with input from the site EQ coordinator** has the responsibility for implementing plant procurement procedures and ensuring that procurement personnel are properly trained in performing the EQ program procurement requirements.
- **The site work planning organization with input from the site EQ coordinator** has the responsibility for establishing and implementing schedules that ensure plant procurement and maintenance activities are performed in a timely manner to support the EQ program requirements.

4.4.4 EQ PROCESS

In establishing the original qualification basis for the equipment and in developing the EQ Master List and EQ procedures, all equipment within the scope of 10 CFR 50.49 was reviewed per the requirements of the quality assurance program. Each test report was reviewed, a test report summary was placed on file, and each piece of equipment, by tag number, was reviewed to document that qualification of the equipment was adequate for its intended application.

The EQ process is controlled by the EQ Master List and the EQ procedures, which are described as follows:

EQ Master List

The EQ Master List provides an up-to-date, controlled listing of electrical equipment in the Hatch EQ program. All EQ Master List information must be originated and revised according to the procedure which controls the EQ program. The EQ Master List provides the following equipment information:

- Plant tag number of the equipment
- The manufacturer and model or series number for the equipment
- The building, floor elevation, and specific location of the equipment
- The applicable EQ QDP which addresses component qualification and maintaining the qualification of the equipment

EQ Maintenance

The Installation/Maintenance Procedure Outline (I/MPO) of the QDP defines the specific requirements for installing and maintaining EQ equipment in its qualified configuration. The I/MPO ensures consistency in maintaining the qualification of all electrical equipment within the scope of 10 CFR 50.49.

The EQ installation and maintenance information in the I/MPO is incorporated into the plant procedure(s) which control the EQ maintenance activities. The I/MPO may specifically address activities such as the following:

- EQ mandated maintenance required to maintain the equipment qualification
- Qualified life of the equipment, any component part to be replaced, and the replacement interval (e.g., replace cover o-ring every 18 months)
- Sealing of the equipment cable entrance to prevent moisture intrusion, as required
- Installation and mounting configurations required to maintain qualification
- Shelf life or storage requirements
- Procurement and reorder information specific to the equipment

Documentation such as maintenance manuals, test reports, calculations, and installation specifications from which the maintenance requirements originate, or which must be used to implement the maintenance requirements, is referenced in the I/MPOs. The requirements contained in the I/MPOs are incorporated not only into craft work procedures (maintenance, termination, sealing, installation), but also the work planning/management system (scheduling and replacement), and procurement procedures.

EQ Aging Management

For EQ components that are not qualified to the end of the extended operating period, aging effects will continue to be managed in accordance with the current licensing basis. 10 CFR 50.49 states: ". . . The equipment must be replaced or refurbished at the end of this designated life unless ongoing qualification demonstrates that the item has additional life."

Replacement of EQ Equipment

Prior to the expiration of the qualified life of a piece of EQ equipment, a maintenance work order is generated by the Hatch work management system to alert plant personnel that the equipment is scheduled for replacement in the near future. Several options are available:

- **Replace the existing component with an identical component -** This option only requires the generation of a work order and any necessary update to the EQ documentation to reflect component replacement, since all the required qualification documentation and procedures already exist.
- **Replace the equipment with different equipment which is already evaluated under the EQ program -** When new or replacement EQ equipment, which is currently addressed in the EQ program, is installed in the plant, the EQ Master List and documentation are changed to reflect the change in the QDP associated with the component. A review is performed which confirms that the EQ documentation:
  - Addresses the specific manufacturer and model number of the equipment.

- Identifies the plant areas in which the component is qualified to be installed.
- Identifies the applicable EQ test report and evaluation.
- Identifies additional documentation relevant to the application versus the tested configuration and test parameters.
- Identifies the normal and postulated accident environments to which the equipment is subject.
- Identifies and records "upgrades" of components qualified to DOR Guidelines to components qualified to the 10 CFR 50.49 requirements.
- Confirms that the new or replacement component is qualified for its application.

- **Replace the equipment with different equipment which is not currently evaluated under the EQ program** – Prior to replacing a piece of equipment with one not currently addressed in the EQ program, an EQRE is prepared that verifies qualification of the equipment. The EQRE, commonly also referred to as a "50.49 Checklist," includes information such as the following:

  - **Equipment Data** - Includes data such as equipment tag numbers, manufacturer, QA condition, specifications, and applicable test report.
  - **Functional Review** - Determines applicability of 10 CFR 50.49 to the equipment; i.e., installed in a postulated harsh environmental area, required to operate during an accident, etc.
  - **Environmental Qualification Review** - Examines appropriate aspects such as test parameters versus installed location accident parameters, operability times, qualified life, equipment tested versus installed equipment, and test report anomalies.

  The information identified above is evaluated and a determination is made whether or not the equipment is qualified for the intended application. For new qualifications, the QDP is then prepared, which provides complete supporting documentation, including test report(s) and evaluations, correspondence, calculations, System Component Evaluation Worksheets (SCEWs), and installation and maintenance requirements.

- **Reanalyze qualified life calculations -** The reanalysis is performed for specific applications to extend the qualified life if excess conservatism exists in the original qualified life calculation. Conservatisms may exist in parameters such as the assumed ambient temperature of the equipment, an unrealistically low activation energy, or in the application of equipment (for example, deenergized versus energized). The reanalysis is documented under a Qualification File Review Checklist (QFRC). The QFRCs document all changes to the EQ Central File. Typically, the guidelines outlined in EPRI methodologies and processes to optimize environmental qualification replacement intervals are followed (Ref. 14). Specific aspects of the way a reanalysis is performed are discussed below:

- **Analytical Methods -** The Arrhenius methodology is the thermal model used to perform a reanalysis. During normal operations, equipment is only subjected to ambient humidity levels (20-90%), which was also dismissed as an aging stressor per the NRC EQ Task Action Plan (Ref. 15). EQ equipment is typically sealed and cable insulation is protected from the occasional inadvertent spray. Exposure to moisture due to leaks is investigated on a case-by-case basis. The analytical method used for radiation reanalysis identified the 40-year radiation dose from the EQ criteria manual for the area where the equipment is installed, multiplied that value by the ratio of the evaluation period divided by 40 years (e.g., for license renewal 60 years/40 years, or 1.5), and added the applicable accident radiation dose to obtain the total integrated dose for the equipment. Southern Nuclear has specifically assessed the impact of life extension from 40 to 60 years on the EQ radiation exposures for both units.
- **Data Collection & Reduction Methods -** Reducing excess conservatisms in the equipment service temperatures used in existing analyses is the chief method used for reanalysis. Temperature data used in a reanalysis is obtained from actual temperature measurements in the area around the equipment being reanalyzed. Temperature measurements can be obtained in several ways, examples of which are through monitors used for Technical Specification compliance, other installed monitors, measurements made by plant operators during surveillance rounds, and temperature sensors on specific components. A representative number of temperature measurements are mathematically reduced to arrive at a temperature used in a reanalysis. Temperatures may be used in several ways in a reanalysis such as (a) using the actual calculated temperature, or (b) using the calculated temperature to validate or show conservatism when using the a design temperature for a reanalysis.
- **Underlying Assumptions -** Conservatisms in the EQ equipment qualification analyses have been maintained sufficiently to absorb environmental changes occurring due to plant modification and events. Major plant modifications or events at Plant Hatch of sufficient duration (such as power uprates) that may change temperature, pressure, and/or radiation values used in the underlying assumptions or in the EQ calculations, are addressed in the design phase prior to implementation of the plant modification or operational change. The process by which changes to the underlying assumptions are made is discussed in the section of this summary program description entitled Plant Environmental Changes**.**
- **Acceptance Criteria & Corrective Actions -** Adequate margin, as suggested in IEEE Std. 323-1974 and DOR Guidelines, is maintained in all reanalyses, or adequate justification for not maintaining margin is provided. If the reanalysis does not maintain adequate margin and less margin cannot be justified, the equipment qualification is not extended and the equipment is replaced (for example) as scheduled prior to the expiration of the existing qualification.

Refurbishment of EQ Equipment

When equipment needs refurbishment, it is typically replaced with new equipment or previously-refurbished equipment taken out of storage. The removed equipment is then discarded or refurbished and placed in storage. Qualified equipment is required to be refurbished before it can be placed back into storage, if the equipment is to be used in EQ applications following storage. Refurbishment is performed in a manner that preserves its qualification. This is typically accomplished by replacing "soft" items such as gaskets, seals, and wires which have a limited life.

The EQ limited-life replacement parts are identified in the I/MPO and EQ maintenance procedures and vendor manuals for a particular piece of equipment, manufacturer, and model. Additionally, guidance for shelf life of refurbished equipment is contained in the documentation.

Procurement of EQ Equipment

Procurement policy and criteria for EQ equipment within the scope of 10 CFR 50.49 are controlled by Southern Nuclear procedure(s) for equipment procurement, the site procedure(s) for procurement, and the Nuclear Quality Assurance Program.

Procurement of like-for-like replacement EQ equipment is controlled, such that the procured equipment is as good as or better than the original equipment. The procurement process also assures applicable performance requirements and qualification criteria are met. Information is found in the component's QDP to facilitate procurement, such as the manufacturer or vendor from which to purchase the equipment, the test reports to be referenced on the requisition, and equipment specifications, etc.

Southern Nuclear reviews specifications for procurement of new EQ equipment to ensure applicable performance requirements and qualification criteria are met. Test plans are reviewed and approved prior to testing to assure compliance with the specification. Upon receipt of a new test report, the responsible engineer will initiate an EQ test report evaluation that establishes the qualification of the equipment. A copy of the evaluation is also inserted into the QDP. Updating the EQ Master List and the QDP are handled similar to the replacement process addressed above.

Plant Environmental Changes

Plant environmental conditions (both normal and accident) are documented in an Engineering Specification (Ref. 16). This specification identifies the harsh environment areas of the plant for LOCAs, HELBs, and radiation consistent with the CLB. Section A of the Central File includes the different temperature and pressure profiles for the various accident scenarios including worst-case composite accident profiles for the various containment and reactor building harsh environment areas. Section F of the Central File and the QDPs include supporting calculations for these accident profiles and radiation total integrated doses. All specifications, calculations, and the other Central File documents are controlled documents.

The measurements of critical parameters (e.g., containment temperatures for Technical Specification requirements) are taken on an ongoing basis. Southern Nuclear reviews changes in environmental parameters, whether as found or anticipated due to an impending design change.

When a significant environmental change is identified, a review of the qualification of affected EQ equipment is performed and applicable changes are made to the equipment's qualified life and QDP documentation. The EQ calculations, Specification, and accident profiles, if appropriate, are revised to reflect the new operating conditions.

4.4.5 ENVIRONMENTALLY QUALIFIED EQUIPMENT SUBJECT TO TLAA DEMONSTRATION

Figure 4.4-1 through Figure 4.4-107 contain detailed evaluations of the equipment qualifications for Plant Hatch. The EQ Program referred to in these figures is the one discussed in sections 4.4.1 through 4.4.4 of the LRA.

Figure 4.4-1 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor-Operated Valve (MOV)
Specific Description:	Limitorque Corp. SB, SMB Actuators, DC Service
Location:	Outside Containment
QDP:	Unit 1/2, QDP 1B/1B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The qualified life has been projected to the end of the period of extended operation for all applications when considering thermal aging only. Seven of these MOVs are not currently qualified through the period of extended operation due to a life-limiting radiation total integrated dose. The qualified lives limited by radiation are as follows:

Unit 1 MOVs located in the pipe chase have a qualified life of 50 years, and MOVs in the RWCU heat exchanger room have a qualified life of 59 years.

Unit 2 MOVs located in the pipe penetration room have a qualified life of 40 years; MOVs located in the pipe chase have a qualified life of 47 years; and MOVs in the RWCU heat exchanger room have a qualified life of 59 years.

For MOVs with qualified lives less than 60 years, aging effects will be managed by the EQ program.

Note:

1. Aging for the DC actuator qualification included mechanical aging for a 40-year qualified life, per IEEE 382-1980. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years. If cycle aging cannot be extended to 60 years, then this component will be managed by the EQ Program.

Figure 4.4-2 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor-Operated Valve
Specific Description:	Limitorque Corp. SB, SMB Actuators, AC Service
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 1C/1C
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The component qualified lives have been projected through the end of the period of extended operation when considering thermal aging. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Aging for the BWR containment qualification included mechanical aging, compared to the minimum 500 cycles for a 40-year qualified life, per IEEE 382-1972. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-3 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor-Operated Valve
Specific Description:	Limitorque Corp. SB, SMB Actuators, AC Service
Location:	Outside Containment
QDP:	Unit 1/2, QDP 1E/1E
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Qualified lives have been projected through the end of the period of extended operation when considering thermal aging. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Aging for the Outside BWR containment actuator qualification included mechanical aging for a 40-year qualified life, per IEEE 382-1980. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-4 Equipment Qualification TLAA Demonstration

Commodity Type:	Torque and Limit Switches
Specific Description:	Limitorque SMB, SB, SBD, SMB/HBC
Location:	Inside/Outside Containment
QDP:	Units 1/2, QDP 1F/1F
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Qualified lives have been projected through the end of the period of extended operation when considering thermal and radiation aging.

Note:

1. Aging in the qualification report included mechanical aging for a 40-year qualified life, per IEEE 382-1980. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-5 Equipment Qualification TLAA Demonstration

Commodity Type:	Electrical Penetrations
Specific Description:	General Electric F01 Electrical Penetration Assembly
Location:	Inside Containment
QDP:	Unit 1/2 QDP 2/2
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Using the original thermal aging test data in conjunction with supplemental data, the General Electric F01 electrical penetration assembly qualified lives have been projected through the end of the period of extended operation.

A supplemental General Electric test report was evaluated to extend the radiation qualification to radiation levels greater than the 60-year total integrated dose, plus margin. The General Electric F01 electrical penetration assemblies are considered qualified through the end of the period of extended operation by test and supplemental analysis.

Figure 4.4-6 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable Connector
Specific Description:	Amphenol Type HN Plug Connectors
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 2A/2A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Amphenol Type HN Plug Connectors are used in the electrical penetrations inside the drywell. The Amphenol Type HN plug connector qualified lives have been projected through the end of the period of extended operation based on thermal aging. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-7 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable Connector
Specific Description:	Veam Series CIR Nuclear Multipin Connector
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 2B/2B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Veam Series CIR nuclear multipin connector qualified lives have been established through the end of the period of extended operation for the worst-case normal temperature and radiation conditions at Plant Hatch.

Figure 4.4-8 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks
Specific Description:	States ZWM and NT Series Terminal Blocks
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 4/4
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The States terminal block qualified lives can be projected to the end of the period of extended operation when used in applications outside containment when considering both thermal and radiation aging.

The radiation aging performed on the States ZWM and NT terminal block material does not support extending the qualified life to 60 years for applications inside containment. For these States ZWM and NT terminal blocks, the aging effects will be managed by the EQ program.

Figure 4.4-9 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Control Centers (MCC)
Specific Description:	Allis Chalmers Value Line Mark 1 AC MCCs and Local Starters
Location:	Outside Containment
QDP:	Unit1/2, QDP 6/6
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Southern Nuclear has projected the qualified lives of the MCC subcomponents to the end of the period of extended operation, with the exception of the molded case circuit breakers, thermal overloads, and the control power transformers. For molded case circuit breakers, thermal overloads, and control power transformers, the aging effects will be managed by the EQ program.

Figure 4.4-10 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuse Blocks
Specific Description:	Bussman Class H, K and R Phenolic
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6B/6B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The fuse blocks are installed in MCCs on the elevation 130 ft of the reactor building in both units. The qualified lives have been projected to the end of the period of extended operation at normal service temperatures. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The fuse blocks are qualified to the end of the period of extended operation.

Figure 4.4-11 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Relay
Specific Description:	Struthers - Dunn Relay 219BBX222NE & Socket CX3964NE
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6F/6F
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects.

Conclusion:

The Struthers - Dunn Relay 219BBX222NE & Socket CX3964NE are qualified for use in the MCCs on El. 130 ft of the reactor building. In the test program, accelerated aging times and temperatures were established (also considering coil heat rise) to achieve 40-year life plus the accident plus margin.

The qualified lives could not be extended significantly and, therefore, the aging effects will be managed by the EQ program.

Figure 4.4-12 Equipment Qualification TLAA Demonstration

Commodity Type:	Molded Case Circuit Breaker (MCCB)
Specific Description:	Westinghouse HFB (Thermal Magnetic & Magnetic), HFD, HMCP
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6G/6G
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (iii): Manage the Aging Effects.

Conclusion:

The Westinghouse HFB (Thermal Magnetic & Magnetic), HFD, and HMCP MCCBs are qualified for use in MCCs on El.130 ft of the Reactor Building.

When used in normally energized applications, the qualified life based on thermal aging data is always less than 40 years.

MCCBs in normally deenergized applications have qualified lives calculated as follows, based on thermal aging data:

HFB	56 years
HFD	88 years
HMCP	55 years

The HFDs are qualified to the end of the period of extended operation. Some HFBs and HMCPs are qualified to the end of the period of extended operation, depending on installation date. If not, the aging effects will be managed by the EQ program.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-13 Equipment Qualification TLAA Demonstration

Commodity Type:	Thermal Overload Relays with Heaters
Specific Description:	Westinghouse Type AA and AN Relay w/ FH Series Heater Element
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6H/6H
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse Type AA and AN Thermal Overload Relays with FH Series Heater Elements are qualified for use in MCCs on EL. 130 ft of the reactor building.

When used in normally energized applications, the qualified life is less than 40 years based on thermal aging data.

Normally deenergized components have a qualified life of greater than 60 years based on thermal aging.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Qualification of the normally deenergized Westinghouse Type AA and AN thermal overload relay with FH series heater element is valid for the period of extended operation.

Figure 4.4-14 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Control Centers
Specific Description:	Cutler Hammer DC Unitrol MCCs
Location:	Outside Containment
QDP:	Unit1 QDP 7
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Southern Nuclear has projected the qualified lives of the DC MCC subcomponents to the end of the period of extended operation (for both thermal and radiation), with the exception of the molded case circuit breakers, thermal overloads, and control power transformers. For molded case circuit breakers, thermal overloads, and control power transformers, aging effects will be managed by the EQ program.

Figure 4.4-15 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem WCSF Heat Shrinkable Tubing and Kits NESK and NCBK Breakout and Tubing Kits NMCK Nuclear Motor Connection Kits
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8A, 8B, 8J/7A, 7B, 7J
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Raychem kits are used in applications inside and outside containment, and are qualified for 60 years at 194 ^{o}F (90 ^{o}C), which bounds all applications. The components are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

The Raychem kits qualified lives have been projected to the end of the period of extended operation.

Figure 4.4-16 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem HVT and NHVT Kits
Location:	Outside Containment
QDP:	Unit 1/2 QDP 8C/7C
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Raychem kits are used in applications outside containment, and are qualified for 60 years, based on thermal aging. The Raychem materials are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

The Raychem kit qualified lives have been projected to the end of the period of extended operation.

Figure 4.4-17 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem Stub Connection Kit
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8E/7E
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Raychem kit is used in applications inside and outside containment. The Raychem materials are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. All outside containment application qualified lives have been projected to the end of the period of extended operation.

Inside containment applications are qualified for 60 years at ambient temperatures below 187 °F. For inside containment applications with higher service temperatures (and falling short of 60-year qualification), aging effects will be managed by the EQ program.

Figure 4.4-18 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem Nuclear Plant Transition Splice Assembly Kits
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8F/7F
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Raychem Nuclear Plant Transition Splice Assembly kits are used in applications inside and outside containment. The Raychem materials are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. Outside containment application qualified lives have been projected to the end of the period of extended operation.

Inside containment applications at ambient temperatures below 187 °F are considered to have a qualified life of 60 years. For inside containment applications with higher service temperatures (and falling short of 60-year qualification), the aging effects will be managed by the EQ program.

Figure 4.4-19 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem 8-kV Inline Motor Connection Splice Kits
Location:	Outside Containment
QDP:	Unit 1/2 QDP 8H/7H
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Raychem 8-kV Inline Motor Connection Splice kits are used in applications outside containment. The Raychem materials are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The outside containment application qualified lives have been projected to the end of the period of extended operation.

Figure 4.4-20 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem Breakout/Scotchcast 9 Potting Compound
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8K/7K
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Raychem Scotchcast 9 Potting Compound is used in applications inside and outside containment with Raychem Breakout Kits. The Scotchcast material is qualified to radiation levels higher than the worst-case 60-year total integrated dose, plus margin. The outside containment applications will not experience temperatures in excess of 135 °F. All outside containment application qualified lives have been projected to the end of the period of extended operation.

Inside containment applications have a qualified life of 60 years at ambient temperatures below 180 °F. For inside containment applications with localized higher service temperatures (and falling short of 60-year qualification), the aging effects will be managed by the EQ program.

Figure 4.4-21 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Switches
Specific Description:	Electroswitch Series 20 and Series 40 Control Switches
Location:	Outside Containment
QDP:	Unit 1, QDP 9
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Electroswitch Series 20 and Series 40 control switches qualified lives have been projected to the end of the period of extended operation considering thermal aging. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Note:

1. The switches were cycle-aged to simulate 40 years of nuclear generating station service. This cycle-aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-22 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	Target Rock Corporation Model 76HH-002
Location:	Outside Containment
QDP:	Unit 1/2, QDP 10/8
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The original qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Figure 4.4-23 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve Upgrade Modification Kits
Specific Description:	Target Rock Corporation Model 82X-007H
Location:	Outside Containment
QDP:	Unit 1/2, QDP 10A/8A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The original qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Figure 4.4-24 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Operated Globe Valve
Specific Description:	Target Rock Corporation Model 91J-001
Location:	Outside Containment
QDP:	Unit 1, QDP 10B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The qualification test was performed on Target Rock model 82X-007H. Model 91J-001 is qualified by similarity.

The original qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Figure 4.4-25 Equipment Qualification TLAA Demonstration

Commodity Type:	Fan Motor
Specific Description:	Reliance Class H Type RH Insulation System
Location:	Outside Containment
QDP:	Unit 1/2, QDP 11/9
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Reliance Class H Type RH Insulation System fan motors are qualified for use in certain locations outside containment.

The qualified life has been calculated to be 44 years based on thermal aging data. Based on installation dates, the installed fan motors are qualified to the end of the period of extended operation.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-26 Equipment Qualification TLAA Demonstration

Commodity Type:	Insulated and Uninsulated Terminals and Splices
Specific Description:	AMP Special Ind. Insulated and Uninsulated Terminals and Splices
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 13/11
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The AMP Special Ind. insulated and uninsulated terminals and splice qualifications have been projected to the end of the period of extended operation by these calculations. The components are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-27 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wire
Specific Description:	GE Vulkene Internal Panel Wire Model SI-57275
Location:	Outside Containment
QDP:	Unit 1/2, QDP 14A/12A
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The GE Vulkene Internal Panel Wire Model SI-57275 is used in panels outside containment.

The qualification has been projected to the end of the period of extended operation.

Figure 4.4-28 Equipment Qualification TLAA Demonstration

Commodity Type:	Switchboard Wire
Specific Description:	GE Vulkene Supreme Type SIS Wire Model SI-57279 (XLPE)
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 14B/12B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The GE Vulkene Supreme Type SIS Wire Model SI-57279 (XLPE) is qualified for use inside and outside containment.

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The GE Vulkene Supreme Type SIS Wire Model SI-57279 (XLPE) is qualified for 60 years at 188 °F. The wire is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

For inside containment applications with localized higher service temperatures which cannot be projected to the end of the period of extended operation, the aging effects will be managed by the EQ program.

Figure 4.4-29 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Okonite Low and Medium Voltage Power and Control Cables; and Instrument Cables
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 17/14
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Okonite low and medium voltage power and control cable qualified lives, and instrument cable qualified lives have been projected to the end of the period of extended operation when considering thermal aging. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-30 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	BIW Coaxial, and Low Voltage Power, Control and Instrument Cable
Location:	Inside/Outside Containment
QDP:	Unit 1, QDP 18A & 18C
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have be reevaluated at maximum average (actual) service temperatures. The BIW low voltage power, control and instrument cable; and BIW coaxial cable qualified lives have been projected to the end of the period of extended operation when considering thermal aging. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-31 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	BIW Instrument and Control Cable
Location:	Outside Containment
QDP:	Unit 1, QDP 18B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The BIW Instrument and Control Cable qualified lives have been projected to the end of the period of extended operation when considering thermal aging. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-32 Equipment Qualification TLAA Demonstration

Commodity Type:	Splice Tape
Specific Description:	Okonite T-95 Insulating and No. 35 Jacketing Tapes With Cement
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 19/29
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The splice tapes are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The Okonite T-95 insulating and No. 35 jacketing tapes have been qualified for 60 years at 188 °F.

When the Okonite T-95 insulating and No. 35 jacketing tapes are used in inside containment applications where the localized service temperature is greater than 188 °F, the qualified lives are shorter than 60 years. For these Okonite T-95 insulating and No. 35 jacketing tapes, the aging effects will be managed by the EQ program.

Figure 4.4-33 Equipment Qualification TLAA Demonstration

Commodity Type:	Splice Tape
Specific Description:	Okonite T-95 Insulating and No. 35 Jacketing Tapes Without Cement
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 19B/29B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Thermal Aging:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Okonite T-95 insulating and No. 35 jacketing tapes (configured without cement) are qualified for 60 years at 170 °F.

When the Okonite T-95 insulating and No. 35 jacketing tapes (configured without cement) are used in applications where the localized service temperature is greater than 170 °F, the qualified lives are shorter than 60 years.

Radiation Aging:

The Okonite T-95 insulating and No. 35 jacketing tapes (configured without cement) were tested to 1.07 E8 rads. For applications where the 60-year normal dose plus accident dose plus 10% margin exceeds 1.07 E8 rads, the qualified life is less than 60 years due to radiation. The worst-case radiation environment occurs in the drywell, where the 60-year total integrated dose is as high as 1.22 E8 rads. In this worst case, the qualified life is limited to 48 years based on radiation.

Qualified Life

The qualified life of a splice is currently the most limiting (the lesser) of the two qualified lives.

Many splices have been projected to the end of the period of extended operation. For others, the aging effects will be managed by the EQ program.

Figure 4.4-34 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	ASCO NP and 206 Series (Deenergized only)
Location:	Outside Containment
QDP:	Unit 1/2, QDP 22/20
Methodology:	NUREG 0588
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Only deenergized ASCO NP and 206 Series solenoid valves located outside containment are included. The 206 series, and models NP8344 and NP8320 qualifications are valid for the period of extended operation for all outside containment applications.

Based on thermal aging data, Models NP8321 and NP8316 have been projected to the end of the period of extended operation for all applications except the Unit 1 torus, personnel access room, and steam chase. In these areas the qualified lives are less, and the aging effects will be managed by the EQ program.

The ASCO NP and 206 Series solenoid valves are qualified to radiation levels greater than the worst-case 60-year total integrated dose.

Note:

1. The ASCO NP and 206 Series solenoid valves were electrically cycled at maximum operating pressure. Prior to extending the qualified lives beyond the current operating license term, the qualified life based on the cycle aging data will be addressed in the current term.

Figure 4.4-35 Equipment Qualification TLAA Demonstration

Commodity Type:	Limit Switches
Specific Description:	NAMCO EA180 and EA740
Location:	Inside/Outside Containment
QDP:	Unit1/2, QDP 23/15
Methodology:	NUREG 0588, 10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The NAMCO EA180 and EA740 limit switches are qualified for use inside and outside containment. Qualified lives vary depending on application-specific ambient temperatures and radiation levels. For many applications, qualification is valid for the period of extended operation when considering thermal aging and radiation aging. Others have been projected to the end of the period of extended operation. When the qualified life is less than 60 years based on both thermal aging and radiation aging, qualified life is based on the most limiting of the two, and the aging effects will be managed by the EQ program.

Note:

1. The NAMCO EA180 and EA740 limit switches were cycled to simulate the operating life (per IEEE 323-1974), in all test programs except one. In that test program, switches were cycle-aged to simulate a 6-year life (per IEEE 382-1980). Prior to extending the qualified lives within or beyond the current operating license term, the qualified life based on the cycle aging data will be addressed in the current term, to assess cycle aging impact on qualified life.

Figure 4.4-36 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	Pressure Controls, Inc. (PCI) Model PPD 147D8668P003
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 25/25
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Component qualified lives in the drywell, steam chase, and personnel access have been reevaluated using actual service temperatures. The Pressure Controls pressure switches are qualified for 60 years at temperatures at or below 136 °F. At higher service temperatures, the qualified lives are less and the aging effects will be managed by the EQ program. The pressure switches are qualified to radiation levels greater than the worst-case 60-year total intregrated dose, plus margin.

Note:

1. Operational cycling was performed by the vendor. Evaluation of this data shows that the product performance qualification specification requirement was met, and that there was no degradation due to operational cycle aging. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-37 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Anaconda Low Voltage Power, Control, Instrumentation Cables and Internal Panel Wiring
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 27/27
Methodology:	NUREG 0588
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Anaconda low voltage power, control, instrument cables and internal panel wiring are qualified for 60 years at 158 °F. At higher service temperatures, the qualified lives are less and the aging effects will be managed as described by the EQ program. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-38 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Anaconda Low Voltage Power, Control, and Instrumentation Cables
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 27A/27A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Anaconda low voltage power, control, and instrument cables are all qualified for 60 years at 158 °F. At localized higher service temperatures, the qualified lives are less and the aging effects will be managed by the EQ program. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-39 Equipment Qualification TLAA Demonstration

Commodity Type:	Radiation Detector and Cable
Specific Description:	Victoreen Model 877-1 Detector and Model 878-1-9 Cable
Location:	Inside Containment
QDP:	Unit 1/2, QDP 28/30
Methodology:	NUREG 0588 Cat.1
TLAA Demonstration Option:	Detector: Criterion (i): Valid for the Period of Extended Operation Cable: Criterion (iii): Manage the Aging Effects

Conclusion:

No thermal aging was required for the detector, as all parts are stainless steel, nickel, or aluminum. The radiation detector is not age-sensitive, and is qualified for 60 years. The detector is refurbished, recalibrated, and recertified every 5 years.

The qualified life of the Victoreen model 878-1-9 cable assemblies could not be projected to the end of the period of extended operation based on the actual service temperatures. For cable assemblies, the aging effects will be managed by the EQ program.

The detector and cable are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-40 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Operated Globe Valves
Specific Description:	Target Rock 82VV Series
Location:	Outside Containment
QDP:	Unit 1/2, QDP 29/31
Methodology:	NUREG 0588, Cat. I
TLAA Demonstration Option:	Unit 1 - Criterion (ii): Projection to the End of the Period of Extended Operation. Unit 2 - Criterion (i): Valid for the Period of Extended Operation

Conclusion:

For Unit 2, the original qualification is valid for the period of extended operation, with minor documentation changes.

For Unit 1, the original qualification of the Target Rock 82VV solenoid valves has been projected to the end of the period of extended operation based on the normal operating temperatures of the installed locations.

The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-41 Equipment Qualification TLAA Demonstration

Commodity Type:	Conduit Seal
Specific Description:	Rosemount 353C
Location:	Outside Containment
QDP:	Unit 1/2, QDP 30/32
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

The thermal aging analysis is presented in the test report. A qualified life of 60 years is given for an ambient operating temperature of 115 °F.

The Rosemount 353C conduit seals qualification has been projected to the end of the period of extended operation for all current Unit 1 and 2 applications.

The conduit seals are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-42 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	Valcor V526 Series (De-energized)
Location:	Outside Containment
QDP:	Unit 1/2, QDP 31/33
Methodology:	NUREG 0588, Cat. I
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

The original qualification covers both energized and deenergized solenoid valves. The energized solenoid valves have a qualified life less than 40 years, and are on a schedule for repetitive replacement. This demonstration covers only the deenergized solenoid valves.

For the deenergized solenoid valves, qualified life has been projected to the end of the period of extended operation using vendor test report aging data. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. The valve was cycle tested. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-43 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	Static-O-Ring Model 4N6-B5-NX-C1A -JJTTX6
Location:	Outside Containment
QDP:	Unit 1/2, QDP 32/65
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The qualified lives are greater than 60 years based on thermal aging. The switches are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Note:

1. The Static-O-Ring Model 4N6-B5-NX-C1A -JJTTX6 is qualified by cycle testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-44 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ
Location:	Outside Containment
QDP:	Unit 1/2, QDP 32A/65A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ pressure switch qualification covers applications in the Northeast and Southeast Diagonals only. Based on normal design temperatures in these areas, qualified life is calculated to be 58 years for Unit 1 and 44 years for Unit 2. Although this is less than 60 years for both units, based on installation dates, all installed components are qualified to the end of the period of extended operation. In addition, the switches are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Existing qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Note:

1. The Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ is qualified by cycle testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-45 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Element
Specific Description:	Pyco, Inc. Models122-7026 and 122-4030-04
Location:	Outside Containment
QDP:	Unit 1/2, QDP 33/35
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to End of the Period of Extended Operation.

Conclusion:

The Pyco, Inc. Models122-7026 and 122-4030-04 temperature element qualifications have been projected to the end of the period of extended operation based on thermal aging data. The components are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-46 Equipment Qualification TLAA Demonstration

Commodity Type:	Limit Switch
Specific Description:	NAMCO EA170 Series
Location:	Outside Containment
QDP:	Unit 1/2, QDP 34/36
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The NAMCO EA170 Series limit switches are qualified for use in reactor building elevation 130 ft. Based on thermal aging data, the qualified lives of the limit switches have been projected to the end of the period of extended operation, with periodic replacement of the elastomeric subcomponents. The limit switches are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. During testing, the NAMCO EA170 Series limit switches were cycle-aged. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-47 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Elements and RTV Sealant
Specific Description:	Weed Model 1AOD/611-1B-C-4-C-2-A2-0
Location:	Inside Containment
QDP:	Unit 1/2, QDP 35/37
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

For components inside the containment, the pipe chase, and the pipe penetration room qualified lives have been reevaluated using actual service temperature measurements, yielding a range of qualified lives depending on the application-specific temperature. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

For components with qualified lives less than 60 years, the aging effects will be managed by the EQ program.

Figure 4.4-48 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Sensor Assemblies
Specific Description:	Weed Assembly Nos. N9017D1B (Dual); N9017S1B (Single)
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 48A/57A (Outside Containment) Unit 1/2, QDP 35B/37B (Inside Containment)
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Weed temperature sensor assembly qualifications have been projected to the end of the period of extended operation for all outside containment applications based on design ambients.

The qualified lives for temperature elements located inside containment, pipe penetration room, and pipe chase could not be projected to the end of the period of extended operation based on thermal aging.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

For components with qualified lives less than 60 years, the aging effects will be managed by the EQ Program.

Figure 4.4-49 Equipment Qualification TLAA Demonstration

Commodity Type:	Primary Containment Post-LOCA H2 and O2 Analyzer
Specific Description:	Comsip, Inc. Model K-IV
Location:	Outside Containment
QDP:	Unit 1/2, QDP 37/39
Methodology:	NUREG 0588, Cat. I
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Comsip, Inc Model K-IV primary containment post-LOCA H2 and O2 analyzer has been qualified to the end of the period of extended operation.

The Reliance pump motor for the H2 and O2 analyzer was qualified in a separate test program and supplied by Reliance to Comsip. The motor is qualified to the end of the period of extended operation.

The Bostrad cable for the H2 and O2 analyzer was qualified in a separate test program and supplied by Boston Insulated Wire and Cable to Comsip. The cable is qualified to the end of the period of extended operation.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-50 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wiring
Specific Description:	Raychem Flamtrol Internal Panel Wiring
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 39/47
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Raychem Flamtrol Internal Panel Wiring qualification has been projected to the end of the period of extended operation for all applications. The wire is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-51 Equipment Qualification TLAA Demonstration

Commodity Type:	Heat Trace System for Post-LOCA H2 and O2 Analyzers
Specific Description:	Thermon Model SSK, Heater Cable Pipe Assembly (HCPA)
Location:	Outside Containment
QDP:	Unit 1/2, QDP 40/41
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Unit 2: Criterion (i): Valid for the Period of Extended Operation Unit 1: Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The heat trace system control panels are exempt from environmental qualification requirements due to location in a mild environment.

For Unit 2, the HCPA qualification is valid for the period of extended operation, with minor documentation changes.

Due to higher Unit 1 design temperature, the HCPA qualified life is less than 60 years. However, the HCPA is qualified to the end of the period of extended operation, based on the date of system installation.

The HCPA is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-52 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor
Specific Description:	GE 5K6339XC166A and 5K6339XC94A RHR and Core Spray Pump Motors
Location:	Outside Containment
QDP:	Unit 1/2 QDP 42/45
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The GE 5K6339XC166A and 5K6339XC94A RHR and core spray pump motors are installed outside containment in the NE and SE corner rooms. The motors were originally qualified for 40 years by test and analysis. The qualified life has been projected to the end of the period of extended operation when considering thermal aging data from the original analysis. The motors are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-53 Equipment Qualification TLAA Demonstration

Commodity Type:	Gauge Pressure Transmitter
Specific Description:	ITT/Barton Model 763
Location:	Outside Containment
QDP:	Unit 1/2, QDP 45/52
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

For installed locations, the qualification has been projected to the end of the period of extended operation when considering thermal aging. The transmitters are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Operational cycling was performed by the vendor. Evaluation of the vendor's operational cycling data shows that the product performance qualification specification requirement was met and that there was no degradation due to operational cycling. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-54   Equipment Qualification TLAA Demonstration

Commodity Type:	Differential Pressure Transmitter
Specific Description:	ITT/Barton Model 764
Location:	Outside Containment
QDP:	Unit 1/2, QDP 46/51
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

For installed locations, the qualification has been projected to the end of the period of extended operation when considering thermal aging. The transmitters are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Operational cycling was performed by the vendor. Evaluation of the vendor's operational cycling data shows that the product performance qualification specification was met and that there was no degradation due to operational cycling. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-55 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Elements
Specific Description:	Weed Model 1AOD/611-1BD-C-6-C-2-A2-0
	GE Model PPD 228B1877
Location:	Outside Containment
QDP:	Unit 1/2, QDP 48/57
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The qualified life exceeds 60 years where average temperatures are 114 °F or less. For all areas outside containment except the Unit 1 and the Unit 2 pipe penetration rooms and pipe chases, the temperature element qualification has been projected to the end of the period of extended operation when considering thermal aging.

The qualified lives for temperature elements located inside the pipe penetration room and pipe chase (where the actual temperatures can exceed 114 °F) have been determined. For these components, aging effects will be managed by the EQ program.

The temperature elements are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-56 Equipment Qualification TLAA Demonstration

Commodity Type:	EMI Filter Assembly
Specific Description:	GE Part No. 228B1892
	ITT Barton Catalog No.0768-1009-B
Location:	Outside Containment
QDP:	Unit 1/2, QDP 49/48
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The qualified life has been projected to the end of the period of extended operation when considering thermal aging for installed applications. The EMI filter assembly is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-57 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Block
Specific Description:	Buchanan NQB112
Location:	Outside Containment
QDP:	Unit 1/2, QDP 50/43
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Based on thermal aging data, the qualified lives of the Buchanan NQB112 terminal blocks have been projected to the end of the period of extended operation for all applications except those in the Unit 1 torus, pipe penetration room and pipe chase. In these areas, the normal ambient temperature yields a qualified life of 47 years. For terminal blocks used in these areas, aging effects will be managed by the EQ program. The terminal blocks are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-58 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switches
Specific Description:	Square D Model 9012-ACW-22 Pressure Switches
Location:	Outside Containment
QDP:	Unit 1/2 QDP 51/56
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Square D Model 9012-ACW-22 pressure switches in the HPCI turbine control panel is qualified for 40 years . The thermal aging data do not support extending the qualified life to 60 years. The Square D Model 9012-ACW-22 pressure switches aging effects will be managed by the EQ program.

Figure 4.4-59 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks and Speed Detector
Specific Description:	Square D Model 1828 Terminal Block and Woodward Model 1680 Magnetic Pickup Speed Detector
Location:	Outside Containment
QDP:	Unit 1/2 QDP 51B / 56B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Square D Model 1828 terminal block and woodward model 1680 magnetic pickup speed detector is used in the HPCI turbine controls located outside containment. The analysis and data will support a 60-year qualified life based on an ambient temperature of 148 °F (maximum design basis event (DBE) temperature). The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualified lives of the Square D Model 1828 terminal block and Woodward Model 1680 magnetic pickup speed detector have been projected to the end of the period of extended operation.

Figure 4.4-60 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	GE/ASCO Model HVA-176-816
Location:	Outside Containment
QDP:	Unit 1/2, QDP 52/53
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The GE/ASCO Model HVA-176-816 solenoid valve is qualified for use on the 130 ft elevation of the reactor building. The qualified life of the component has been projected to the end of the period of extended operation when considering thermal aging. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. During testing, the component was cycle-aged. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-61 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Brand-Rex Low Voltage Power, Control, Instrumentation Cables and Internal Panel Wiring
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 54/18
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Brand-Rex low voltage power, control, instrument cables, and internal panel wiring are all were not qualified for 60 years at 189 °F. At localized higher service temperatures, the cable qualified lives weren't projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-62 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Rockbestos Firewall III Control and Instrumentation Cables
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 57/61
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Rockbestos Firewall III control and instrumentation cables are qualified for 60 years at 189 °F, which includes all applications. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-63 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Rockbestos Adverse Coaxial, Twinaxial, and Triaxial Cable
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 57A,B/61A,B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Rockbestos adverse coaxial, twinaxial, and triaxial cable are all qualified for 60 years at 151 °F, which incudes all current applications. The cables are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-64 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks and Lugs
Specific Description:	Marathon, Buchanan, GE, Curtis, Burndy, Hollingsworth, Thomas & Betts Terminal Blocks and Lugs - Various
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 58/62
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects (Unit 2 Terminal Blocks only.)

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures.

The Marathon, Buchanan, GE, Curtis, Burndy, Hollingsworth, and Thomas & Betts terminal blocks and lugs (various) are all qualified for 60 years for all applications on Unit 1.

For Unit 2, Lugs are qualified for 60 years in all applications. The terminal blocks are qualified for 60 years, except in a few specific applications that exceed the 60-year qualified life temperature. Where service temperatures exceed the specified temperature, the terminal block qualified lives were not projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-65 Equipment Qualification TLAA Demonstration

Commodity Type:	Space Heater
Specific Description:	Ward Leonard 30/25F Limit Switch Compartment Space Heater
Location:	Outside Containment
QDP:	Unit 1/2 QDP 59/63
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Ward Leonard 30/25F limit switch compartment space heaters are installed in the limit switch compartments of Limitorque MOV operators. These heaters are wire wound or carbon film resistive elements encapsulated in a vitreous enamel or ceramic glaze. The materials of construction for the heaters are not considered age sensitive to either temperature or radiation exposures. Therefore, any installed Ward Leonard 30/25F limit switch compartment space heaters are considered qualified to 60 years (valid for the period of extended operation).

Figure 4.4-66 Equipment Qualification TLAA Demonstration

Commodity Type:	High Temperature Wire
Specific Description:	Valcor Silicone with Glass Braid
Location:	Inside /Outside Containment
QDP:	Unit 1/2, QDP 60/64
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

This cable is used as lead wire for EQ components. The qualified life of the wire has been projected to the end of the period of extended operation when considering thermal aging. The wire is qualified to radiation levels greater than the worst-case 60-year total integrated dose.

Figure 4.4-67 Equipment Qualification TLAA Demonstration

Commodity Type:	Conduit Seals and Thread Sealant
Specific Description:	Patel Model 841206 Conduit Seals and Patel P-1 Thread Sealant
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 61/66
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

The Patel P-1 thread sealant has a useful temperature range of -400 to 850 °F. The material is a highly temperature-stable graphite, and is exempt from thermal aging. It is also insensitive to radiation. Qualification has been projected to the end of the extended operation.

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Patel Model 841206 conduit seals are qualified for 60 years at 172 °F.

When the Patel Model 841206 conduit seals are used in applications where the service temperature is greater than 172 °F, the qualified lives are shorter than 60 years. For these Patel Model 841206 conduit seals, the qualified lives could not be projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program. The conduit seals are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-68 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Block
Specific Description:	Marathon 216HB Terminal Block with Screws
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 63/67
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The qualified lives of the Marathon 216HB terminal blocks have been projected to the end of the period of extended operation based on the normal operating temperatures in the installed locations. The terminal blocks are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-69 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Switches
Specific Description:	Fenwal Thermoswitch (Model 18021-0)
Location:	Outside Containment
QDP:	Unit 1 QDP 66
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Fenwal Thermoswitch (Model 18021-0) qualification is valid for the period of extended operation at normal ambient temperatures. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. The vendor performed operational cycling during the qualification test program. Evaluation of the vendor's cycling data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-70 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Relay
Specific Description:	Allen Bradley Model 700-N and 700DC-N Control Relays
Location:	Outside Containment
QDP:	Unit 1/2 QDP 67A/72E
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Allen Bradley Model 700-N and 700DC-N control relays in the standby gas treatment system control panels are qualified for 50 years. The thermal aging data do not support extending the qualified life to 60 years. For Allen Bradley Model 700-N and 700DC-N relays, the aging effects will be managed by the EQ program.

Note:

1. The Allen-Bradley control relays were cycled during qualification testing. Prior to extending the qualified lives beyond 40 years, this cycle aging data will be reevaluated to assess impact on qualified life.

Figure 4.4-71 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Transformer
Specific Description:	General Electric Model 9T56Y2830 and 9T58B2830 Control Transformers
Location:	Outside Containment
QDP:	Unit 1 QDP 67C
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The General Electric Models 9T56Y2830 and 9T58B2830 control transformers in the standby gas treatment system control panels are qualified for 42 years. The thermal aging data do not support extending the qualified life to 60 years. For the General Electric Models 9T56Y2830 and 9T58B2830 control transformers, aging effects will be managed by the EQ program.

Figure 4.4-72 Equipment Qualification TLAA Demonstration

Commodity Type:	Pilot Light
Specific Description:	General Electric CR104L Pilot Light
Location:	Outside Containment
QDP:	Unit 1 QDP 67D
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The General Electric CR104L pilot light assemblies are used in the standby gas treatment system. Qualification is valid for the period of extended operation. The component is qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-73 Equipment Qualification TLAA Demonstration

Commodity Type:	Contactor
Specific Description:	Allen Bradley 702LP-AOD94 Magnetic Latch Contactor
Location:	Outside Containment
QDP:	Unit 1 QDP 67E
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Allen Bradley 702LP-AOD94 magnetic latch contactor in the standby gas treatment system control panels is qualified for 48 years when considering thermal and radiation. The thermal aging data do not support extending the qualified life to 60 years. For the Allen Bradley 702LP-AOD94 magnetic latch contactors, aging effects will be managed by the EQ program.

Figure 4.4-74 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wire
Specific Description:	American Insulated Wire Corporation XHHW 600 V Panel Wire
Location:	Outside Containment
QDP:	Unit 1 QDP 67F
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The American Insulated Wire Corporation XHHX 600-V internal panel wire in the standby gas treatment system control panels is qualified for 40 years when considering thermal and radiation. The thermal aging data do not support extending the qualified life. For the American Insulated Wire Corporation XHHX 600-V internal panel wire, the aging effects will be managed by the EQ program.

Figure 4.4-75 Equipment Qualification TLAA Demonstration

Commodity Type:	Heater Elements
Specific Description:	Chromalox Heater Elements Models 50-47499 & 33-47499
Location:	Outside Containment
QDP:	Unit 1/2 QDP 68/75
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Chromalox heater elements (Models 50-47499 & 33-47499) are qualified for more than 60 years at the normal plant ambient temperatures. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualification is valid for the period of extended operation.

Note:

1. The vendor performed operational cycling during the qualification test program. Evaluation of the vendor's cycling data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-76 Equipment Qualification TLAA Demonstration

Commodity Type:	Electrical Penetration
Specific Description:	Conax Buffalo Corp. 7KPO-10001-01, -02, and -03
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 69/69
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

The Conax Buffalo Corporation 7KPO-10001-01, -02, and -03 electrical penetration thermal aging data support a qualified life of 60 years. The penetrations are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The Conax Buffalo Corporation 7KPO-10001-01, -02, and -03 electrical penetration qualifications have been projected to the end of the period of extended operation.

Figure 4.4-77 Equipment Qualification TLAA Demonstration

Commodity Type:	Connectors
Specific Description:	EGS Quick Disconnects and Grayboot Connectors
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 70/76
Methodology:	10 CFR 50.59
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The EGS Quick Disconnect and Grayboot Connector qualified lives have been projected to the end of the period of extended operation for all currently installed applications.

For future applications at certain higher service temperatures (and falling short of qualification through the renewal term), the quick disconnects and grayboot connectors aging effects will be managed by the EQ program.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-78 Equipment Qualification TLAA Demonstration

Commodity Type:	Splice Tape
Specific Description:	United Controls International Model UCI-003XS
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 80/80
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The United Controls International Model UCI-003XS splice tape was recently qualified for new applications at Plant Hatch. The tape qualification is valid for the period of extended operation.

Figure 4.4-79 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Eaton (Samuel Moore) Instrumentation and Thermocouple Cables
Location:	Inside/Outside Containment
QDP:	Unit 2, QDP 17A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Eaton (Samuel Moore) instrumentation and thermocouple cables are qualified for 60 years at 187 °F. At localized higher service temperatures, the cable qualification was not projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-80 Equipment Qualification TLAA Demonstration

Commodity Type:	Instrument and Thermocouple Cable
Specific Description:	Samuel Moore Type 1902 and 1952 EPDM/Hypalon Instrumentation and Thermocouple Cable
Location:	Outside Containment
QDP:	Unit 2 QDP 17B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The test data for the Samuel Moore Type 1902 and 1952 EPDM/Hypalon instrumentation and thermocouple cables support a qualified life in excess of 60 years at the normal operating temperatures. The cables are qualified to radiation levels geater than the worst-case 60-year total integrated dose, plus margin. The qualified lives of the Samuel Moore Type 1902 and 1952 EPDM/Hypalon instrumentation and thermocouple cables have been projected to the end of the period of extended operation.

Figure 4.4-81 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Cerro (Rockbestos) Low Voltage Instrumentation, Control and Power Cables
Location:	Outside Containment
QDP:	Unit 2, QDP 19
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Cerro (Rockbestos) low voltage instrumentation, control and power cables have been projected to the end of the period of extended operation for all applications when considering thermal aging. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-82 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Switches
Specific Description:	General Electric SB-M and SB-1N Control Switches
Location:	Outside Containment
QDP:	Unit 2 QDP 21
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Existing qualification test data for the General Electric SB-M and SB-1N control switches support a qualified life in excess of 60 years at the normal operating temperature. The worst-case 60-year total integrated dose plus margin for the control switch applications is less than the radiation damage threshhold for the nonmetallic materials in the components. The qualified lives of the General Electric SB-M and SB-1N control switches have been projected to the end of the period of extended operation.

Figure 4.4-83 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Control Centers
Specific Description:	General Electric 7700 Series DC MCCs
Location:	Outside Containment
QDP:	Unit 2 QDP 23
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Southern Nuclear has demonstrated that the original qualification methodologies used for the DC MCC subcomponents were also used to project qualification to the end of the period of extended operation, with the possible exception of the molded case circuit breakers, thermal overloads, and the control power transformers. Aging effects for the molded case circuit breakers, thermal overloads, and the control power transformers will be manged by the EQ program.

Figure 4.4-84 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	ITT Barton Model 580A-2 Differential Pressure Switch
Location:	Outside Containment
QDP:	Unit 2, QDP 34
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The ITT Barton Model 580A-2 differential pressure switch is used in the reactor building on the 158 ft elevation. The component already has a calculated qualified life greater than 60 years based on thermal aging. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation.

Note:

1. The test specimens were mechanically cycled during aging. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-85 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Boston Insulated Wire Low Voltage Control and Power Cables; and Coaxial Cable
Location:	Inside/Outside Containment
QDP:	Unit 2, QDP 44
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Boston Insulated Wire low voltage control and power cables are qualified for use inside and outside containment. The Boston insulated wire coaxial cables are qualified for use outside containment.

Common component qualified lives have been reevaluated at maximum average (actual) temperatures. The Boston insulated wire low voltage control and power cables; and coaxial cable qualifications have been projected to the end of the period of extended operation when considering thermal aging for all applications. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-86 Equipment Qualification TLAA Demonstration

Commodity Type:	Form Wound Motor
Specific Description:	Reliance Electric Model FNA-6856 and -6857
Location:	Outside Containment
QDP:	Unit 2, QDP 45A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Reliance Electric Model FNA-6856 and -6857 form wound motors are qualified to the requirements of 10 CFR 50.49 as replacements for original DOR equipment. At this time, there is one 10 CFR 50.49 Reliance Electric Model FNA-6856 installed.

Based on the date of installation for this motor, a 48-year qualification was required to project the qualified life to the end of the period of extended operation.

The qualified life of the installed motor was projected to the end of the period of extended operation based on thermal aging data. The motors are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

For any motors installed in the future, the original qualification is valid for the period of extended operation.

Note:

1. During testing, the motor was cycled through numerous start/stop cycles. This cycle aging will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-87   Equipment Qualification TLAA Demonstration

Commodity Type:	Control and Transfer Switches
Specific Description:	Electro Switch Series 20
Location:	Outside Containment
QDP:	Unit 2, QDP 46
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Electro Switch Series 20 control and transfer switches are qualified for 40 years in the 130 ft elevation of the reactor building and the HPCI room. The qualified life of these three switches could not be projected to the end of the period of extended operation. The aging effects will be managed by the EQ program.

Figure 4.4-88 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Element
Specific Description:	Rosemount 88-51-90 and 88-13-6
Location:	Outside Containment
QDP:	Unit 2, QDP 50
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Rosemount 88-51-90 and 88-13-6 temperature elements are qualified for use in the torus. The calculated qualified lives based on the thermal aging data are greater than 60 years, and the component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The existing qualification remains valid for the period of extended operation with minor qualitative document changes.

Figure 4.4-89 Equipment Qualification TLAA Demonstration

Commodity Type:	Fan Motor
Specific Description:	Farr Co. / Westinghouse Life-line 284T Frame Motor
Location:	Outside Containment
QDP:	Unit 2 QDP 71
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Farr Co. / Westinghouse Life-line 284T frame motor qualification is valid for the period of extended operation at the service temperature in the standby gas treatment system filter train room. The fan motor is qualified to a radiation level greater than the worst-case 60-year total integrated dose, plus margin.

Figure *4.4-90 Equipment Qualification TLAA Demonstration*

Commodity Type:	Control Transformer
Specific Description:	Allen Bradley 1497-N20 Control Transformer (and attached X-277745 Fuse Block)
Location:	Outside Containment
QDP:	Unit 2 QDP 72A
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Allen Bradley 1497-N20 control transformer (and attached X-277745 fuse block) in the standby gas treatment system already has a qualified life in excess of 60 years at normal operating temperature. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation with minor qualitative documentation changes.

Note:

1. Cycle aging performed during testing was based on the Regulatory Guide 1.52 requirement for 40-year life. Qualified life based on cycling will be determined prior to extending the qualified life beyond 40 years.

Figure 4.4-91 Equipment Qualification TLAA Demonstration

Commodity Type:	Molded Case Breakers
Specific Description:	Westinghouse HFB 3070L Molded Case Circuit Breaker
Location:	Outside Containment
QDP:	Unit 2 QDP 72B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Requires Projection to the End of the Period of Extended Operation

Conclusion:

The Westinghouse HFB 3070L molded case circuit breaker qualification has been projected to the end of the period of extended operation at the normal operating temperature in the standby gas treatment system filter train room. The component is qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Note:

1. Cycle aging performed during testing was based on Regulatory Guide 1.52 requirement for 40-year life. Qualified life based on cycling will be determined prior to extending the qualified life beyond 40 years.

Figure 4.4-92 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Starters
Specific Description:	Westinghouse A200 M2CAC Motor Starter and Interlocks
Location:	Outside Containment
QDP:	Unit 2 QDP 72C
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse A200 M2CAC motor starter and interlocks in the standby gas treatment system control panels already have qualified lives in excess of 60 years at the normal operating temperature. The materials of construction are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Westinghouse A200 M2CAC motor starter and interlock qualifications remain valid for the period of extended operation.

Figure 4.4-93 Equipment Qualification TLAA Demonstration

Commodity Type:	Thermal Overload Relay
Specific Description:	Westinghouse Type AN Overload Relay with Heater Elements
Location:	Outside Containment
QDP:	Unit 2 QDP 72D
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse Type AN overload relay with heater elements in the standby gas treatment system control panels have qualified lives in excess of 60 years at the normal operating temperature. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation.

Note:

1. The thermal overloads were cycled during testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-94 Equipment Qualification TLAA Demonstration

Commodity Type:	Contactor
Specific Description:	Allen Bradley 702LP-BOD93 Magnetic Latch Contactor
Location:	Outside Containment
QDP:	Unit 2 QDP 72G
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Allen Bradley 702LP-BOD93 magnetic latch contactor used the standby gas treatment system control panel has a qualified life in excess of 60 years. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. Cycle aging performed during testing was based on the Regulatory Guide 1.52 requirement for 40-year life. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-95 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks
Specific Description:	Buchanan 211 Terminal Blocks
Location:	Outside Containment
QDP:	Unit 2 QDP 72H
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Buchanan 211 terminal blocks in the standby gas treatment system control panels have qualified lives in excess of 60 years at normal operating temperature. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Buchanan terminal block qualification remains valid for the end of the period of extended operation.

Figure 4.4-96 Equipment Qualification TLAA Demonstration

Commodity Type:	Circuit Breakers
Specific Description:	Telemecanique (Imperial) EF3-B070 Circuit Breaker
Location:	Outside Containment
QDP:	Unit 2 QDP 72J
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Telemecanique (Imperial) EF3-B070 circuit breakers in the standby gas treatment system control panels are qualified for 40 years. The thermal aging data do not support extending the qualified life to 60 years. The Telemecanique (Imperial) EF3-B070 circuit breaker aging effects will be managed by the EQ program.

Figure 4.4-97 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuses
Specific Description:	Bussmann Type FNM-5 Dual Element Time Delay Fuse
Location:	Outside Containment
QDP:	Unit 2 QDP 72K
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Bussmann Type FNM-5 dual element time delay fuses in the standby gas treatment system control panels have qualified lives in excess of 60 years at normal operating temperature. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Bussmann Fuse qualification remains valid for the period of extended operation.

Figure 4.4-98 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuses and Fuseblocks
Specific Description:	Bussmann 4482 Fuse Blocks and Bussman AGS and AGC Fuses
Location:	Outside Containment
QDP:	Unit 2 QDP 72L
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation (Fuses) Criterion (iii): Manage the Aging Effects (Fuse Blocks)

Conclusion:

The Bussmann 4482 fuse blocks in the standby gas treatment system control panels are qualified for 50 years. The thermal aging data does not support extending the qualified life to 60 years. The aging effects will be managed by the EQ program.

The Bussman AGS and AGC fuse qualification is valid for the end of the period of extended operation when considering thermal aging data.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-99 Equipment Qualification TLAA Demonstration

Commodity Type:	Pilot Light
Specific Description:	Allen Bradley 800H and 800T Pilot Lights
Location:	Outside Containment
QDP:	Unit 2 QDP 72N
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Allen Bradley 800H and 800T pilot light assemblies in the standby gas treatment system have a qualified life in excess of 60 years at the normal operating temperature. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Allen Bradley 800H and 800T pilot light qualification remains valid for the period of extended operation.

Figure 4.4-100 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wire
Specific Description:	American Insulated Wire Corporation and Triangle Wire Company XHHW 600-V Panel Wire
Location:	Outside Containment
QDP:	Unit 2 QDP 72O
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The American Insulated Wire Corporation and Triangle Wire Company XHHX 600-V internal panel wire in the standby gas treatment system control panels has a calculated qualified life in excess of 60 years at the normal operating temperature. The wire is qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The American Insulated Wire Corporation and Triangle Wire Company XHHX 600-V internal panel wire qualification remains valid for the period of extended operation.

Figure 4.4-101   Equipment Qualification TLAA Demonstration

Commodity Type:	Control Relays
Specific Description:	Allen Bradley Relays (See Below)
Location:	Outside Containment
QDP:	Unit 2, QDP 72P
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The following Allen Bradley control relay models are qualified for use in the standby gas treatment system filter train room of the 185 ft elevation of the reactor building:

- 700-P with 120 VAC coil
- 700-P with 600 VAC coil
- 700DC-P with 125 VDC coil
- 700-N with 120 VAC coil
- 700DC-N with 125 VDC coil
- 700-NA40 Front Deck

The Allen Bradley control relays are qualified for 50 years, with thermal aging limiting the qualified life. The qualified life cannot currently be projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program.

Figure 4.4-102 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Starters and Electrical/Mechanical Interlocks
Specific Description:	Westinghouse A200, A201, and A210 Motor Starters; and Type J Auxiliary Contacts
Location:	Outside Containment
QDP:	Unit 2, QDP 72Q
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Westinghouse A200, A201, and A210 motor starters; and Type J auxiliary contacts are qualified for use in the standby gas treatment system filter train room at the 185 ft elevation of the reactor building.

The qualified life based on thermal aging has been projected to the end of the period of extended operation. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Note:

1. Mechanical aging was performed with 12 VDC and 20-amp loading. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-103 Equipment Qualification TLAA Demonstration

Commodity Type:	Thermal Overload Relays with Heaters
Specific Description:	Westinghouse Type AN Relay with FH Series Heater Element
Location:	Outside Containment
QDP:	Unit 2, QDP 72R
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse Type AN relay with FH series heater element is qualified for use in the standby gas treatment system filter train room at the 185 ft elevation of the reactor building.

The qualified life based on thermal aging is greater than 60 years, and the components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation.

Note:

1. Cycle aging was performed during testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-104 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuses
Specific Description:	Bussmann Types AGS and AGC
Location:	Outside Containment
QDP:	Unit 2, QDP 72S
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Bussmann Types AGS and AGC fuses are qualified for use in the standby gas treatment system filter train room at the 185 ft elevation of the reactor building.

The qualification is by test and material analysis and is valid through the period of extended operation when consdiering thermal aging. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-105 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Switches
Specific Description:	Fenwal Models 27121-0-325 and 27121-0-190
Location:	Outside Containment
QDP:	Unit 2 QDP 73
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Fenwal Model 27121 thermoswitches are qualified for more than 60 years at the normal plant ambient temperatures. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. The vendor performed operational cycling during the qualification test program. Evaluation of the vendor's cycling data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-106 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Switches
Specific Description:	Fenwal Models 18021-0
Location:	Outside Containment
QDP:	Unit 2, QDP 73A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Fenwal Model 18021-0 temperature switch is qualified for use in the standby gas filter train room at the 185 ft elevation of the reactor building. The switch is qualified for greater than 60 years at the normal design temperature, and is qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. The vendor performed operational cycle aging during the qualification test program. Evaluation of the data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-107 Equipment Qualification TLAA Demonstration

Commodity Type:	Flow Switch
Specific Description:	McDonnell & Miller FS7-4V Flow Switch
Location:	Outside Containment
QDP:	Unit 2 QDP 74
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The McDonnell & Miller FS7-4V flow switches in the standby gas treatment system have a qualified life in excess of 60 years at the normal operating temperature. This component is qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be evaluated.

4.5 CONTAINMENT PENETRATION PRESSURIZATION CYCLES

Southern Nuclear identified one containment penetration structural analysis for Plant Hatch that assumed a number of pressurization cycles for 40 years. This calculation was determined to meet all six criteria and, therefore, is a TLAA. The architect engineer performed the structural analysis to provide the design basis for the acceptability of using backing rings for certain types of pipe-to-penetration welds. The effect of the pressurization cycles on the calculation results is minimal. The calculation has been extended to 60 years of operation without change to plant equipment {demonstration through Criterion (ii) of 10 CFR 54.21(c)(1)}.

4.6 REACTOR VESSEL TLAAS

GE reports prepared for Southern Nuclear identify two TLAAs relating to 10 CFR 50 Appendix G requirements for fracture toughness (Section IV). These two requirements pertain to the effects of radiation embrittlement. Another TLAA involves the BWR Vessel and Internals Project (BWRVIP) request for inspection relief of circumferential welds. For Plant Hatch, Southern Nuclear has determined that 54 effective full-power years of reactor operation will carry the reactor vessel through the period of extended operation.

4.6.1 EQUIVALENT CHARPY UPPER-SHELF ENERGY MARGIN ANALYSIS

GE performed an update to the NRC-approved upper shelf energy (USE) equivalent margins analysis (Ref.18). This updated analysis incorporates the effects of irradiation for 54 effective full-power years (EFPY). The updated analysis determines that the generic materials considered will maintain the margins for USE required by 10 CFR 50 Appendix G.

GE reviewed the updated generic analyses with respect to applicability for the Plant Hatch license renewal term. This review is documented in an evaluation performed by GE (Ref. 17). GE determined that the generic analyses are applicable and that, for 54 EFPY, the critical materials would retain sufficient USE to satisfy 10 CFR 50 Appendix G requirements.

4.6.2 NIL-DUCTILITY REFERENCE TEMPERATURE ADJUSTMENTS

GE reevaluated the reduction in fracture toughness of the reactor vessel components due to neutron embrittlement and has determined that the analysis of embrittlement in the belt-line region of the core is a TLAA. The core belt-line region consists of bounding vessel locations adjacent to the active fuel where the neutron fluence will cause a shift in the reference temperature for the nil-ductility point (RT_{NDT}) of the materials.

GE performed a specific analysis for Plant Hatch (Ref. 11) using the criteria defined in the generic analysis (Ref. 18). The GE analysis for Plant Hatch considers the effect of neutron embrittlement for the extended 60-year term by considering 54 EFPY. The analyses include new sets of reactor operating pressure and temperature curves. The results of the analysis indicate that for both units, the adjusted reference temperature for nil-ductility will be less than the 10 CFR 50 Appendix G requirement of 200 °F.

4.6.3 CIRCUMFERENTIAL WELD INSPECTION RELIEF

The BWRVIP provided the technical bases supporting the elimination of RPV circumferential welds from the inservice inspection programs for BWRs as discussed in BWRVIP-74 (Ref. 18). These technical bases are approved for the current license term and are applicable to Plant Hatch. Southern Nuclear must make a plant-specific submittal requesting relief demonstrating how the technical bases were applicable to Plant Hatch.

Appendix E of the NRC's Safety Evaluation Report (SER) for BWRVIP-05 (Ref. 19) documents an evaluation of the impact of license renewal from 32 EFPY to 64 EFPY on the conditional probability of vessel failure. The SER reports that the frequency of cold overpressurization events results in a total vessel failure probability of approximately 5×10^{-7}. The SER conservatively evaluates an operating period of 10 EFPY greater than what is realistically expected for a 20-year license renewal term, i.e., 48 to 54 EFPY. Therefore, this analysis provides a basis for BWRVIP-05 to be approved as a technical alternative from the current inservice inspection requirements of ASME Section XI for volumetric examination of the circumferential welds as they may apply in the license renewal period.

If RPV circumferential weld examinations are still required by ASME Section XI at the point Plant Hatch enters the period of extended operation, Southern Nuclear will submit a specific request for approval of a technical alternative to the Code for Plant Hatch. In this submittal, Southern Nuclear will show that:

- At the expiration of the renewal period, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds given in Appendix E of the SER, and
- Southern Nuclear has implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the NRC SER.

For the purposes of this application, a summary of the demonstration that these two criteria are met follows:

In demonstration that criteria in the first bulleted item above has been satisfied, Southern Nuclear has reevaluated the probability of failure of the welds given the longer operating term associated with a renewed license. In keeping with the guidance of the BWRVIP, (Ref. 18), Southern Nuclear has recalculated the USE and the RT_{NDT} at the end of the renewed license (EOL) for the critical regions of the vessel. The calculations show that the remaining USE margin and the shift in the RT_{NDT} are both still acceptable per the 10 CFR 50 Appendix G requirements. Therefore, the probability of failure of the welds is less than the SER limit.

In demonstration that criteria in the second bulleted item above has been satisfied, Southern Nuclear has in place sufficient procedural control over operations and tests such that the likelihood of the occurrence of low temperature overpressure (LTOP) events is minimized. These procedures are reinforced through normal, periodic, operator training. The procedures and training will be maintained through the extended license term. Southern Nuclear's December 2, 1998, response to Generic Letter 98-05 contains details of the specific procedural controls and training.

Therefore, the basis for eliminating RPV circumferential weld examinations from the ISI Program is not affected by operation of the plant for 60 years. Hence, for License Renewal, the subject TLAAs for RPV circumferential weld examination remain valid for the extended period of operation {demonstration through Criterion (ii) of 10 CFR 54.21 (c)(i)}.

4.7 MAIN STEAM ISOLATION VALVES OPERATING CYCLES

The Plant Hatch FSARs contain statements with regard to the design of the MSIVs for the current license term. Southern Nuclear analyzed these statements for TLAA status. The Unit 2 FSAR paragraph 5.5.5.1, states the following (with a similar reference in the Unit 1 FSAR, subsection 4.6.3):

"The design objective for the valve is a minimum 40-year service at the specified operating conditions. Operating cycles are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter." (Ref. 20)

The FSAR statement refers to mechanical cycles of the valve. Cycling of the valve will lead to wear of the valve disc and valve seat. The wear will accumulate over time (2,050 cycles are assumed in the FSAR statement for 40 years). The statement therefore meets the criteria of a TLAA. However, this kind of wear due to operation of the valve will lead to performance degradation, discoverable through normal leakage monitoring testing. Excessive leakage would lead to refurbishment or repair of the valve seat and disc, as necessary. Once maintenance is performed, the service life of the valve is restored. The components that would experience the wear that the FSAR statement describes are active parts of the valve assembly and would, therefore, not be subject to an aging management review. However, since the aging effect is readily discoverable through normal Technical Specification surveillance testing and repairable maintenance, the TLAA is demonstrated through existing maintenance and surveillance procedures {demonstration through Criteria (iii) of 10 CFR 54.21(c)(1)}.

4.8 GENERAL REFERENCES

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2. Edwin I. Hatch Final Safety Analysis Report, Unit 1, Section A.3.
3. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Paragraphs 3.9.2.1 and 6.3.2.2.1.
4. USNRC Regulatory Guide 1.46, Revision 0, “Protection Against Pipe Whip Inside Containment,” Withdrawn August 11, 1985.
5. Edwin I. Hatch Final Safety Analysis Report, Unit 1, Subsection 4.2.5.
6. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Paragraph 5.4.6.4.
7. Structural Integrity Associates Report Number SIR-99-078, Revision A, “Development of Class 1 Piping Fatigue Formulas and Fatigue Usage Estimates for the Hatch Nuclear Power Plant, Units 1 and 2,” June 1999.
8. “Hatch Units 1 and 2 Torus Fatigue Analysis Report, REA HT-98674 Response”; Revision 0; Southern Company Services, Inc.; Nuclear Engineering and Regulatory Support; April 1999.
9. USNRC Generic Letter 89-013, “Service Water System Problems Affecting Safety-Related Equipment,” July 1989.
10. USNRC Generic Letter 90-005, “Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping,” June 1990.
11. GENE B11-00833-00-01, “Plant Hatch Reactor Pressure Vessel Aging Management Report,” General Electric Company, November 1999 (GE Proprietary).
12. Edwin I. Hatch Final Safety Analysis Report, Unit 1, Section 7.16.
13. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Section 3.11.
14. EPRI TR-104873, “Methodologies and Processes to Optimize Environmental Qualification Replacement Internals,” February 1996.
15. NUREG/CR-6384, “Literature Review of Environmental Qualification of Safety-Related Electric Cables,” April 1996.
16. Plant Hatch Specification SS-2102-238, Revision 7, “Environmental Qualification Requirements for Safety Related Class 1E Electrical Equipment, Components, and Instrumentation,” November 13, 1997.
17. GENE B11-00827-00-01, “Plant Hatch Units 1 and 2 Reactor Pressure Vessel Pressure/Temperature Limits License Renewal Evaluation,” General Electric Company, March 1999.
18. EPRI TR-113596, “BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” BWRVIP-74, September 1999.
19. “Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925),” USNRC, July 28, 1998.
20. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Section 5.5.5.1.
21. B. D. Frew to C. R. Pierce, letter dated September 15, 1999, “Corrosion Allowance for Hatch 1 and 2 Vessel/Piping Systems,” BDF 9912, DRF B11-00827.

Appendix A

FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

CONTENTS

Introduction

The program and activity descriptions presented in Appendix A to the License Renewal Application represent the Plant Hatch commitments for managing aging of the in-scope systems, structures and components during the period of extended operation. These descriptions, as modified and approved during the licensing process, will be incorporated into a new Chapter 18 in the Unit 2 Final Safety Analysis Report following issuance of the new Operating License.

Other changes to the Final Safety Analysis Report, or other licensing basis documents, may be required due to the addition of the new Chapter 18, but not as a direct result of, or part of aging management. Southern Nuclear anticipates making such changes in concert with, but independent of, the addition of Chapter 18 to the Final Safety Analysis Report.

Background

As part of the license renewal effort, Southern Nuclear must demonstrate to the Nuclear Regulatory Commission that the aging effects determined to be applicable to Plant Hatch are adequately managed during the renewal term.

In many cases, existing programs and activities were found adequate for managing aging in the renewal term. In some cases, aging management reviews revealed that programs or activities required some degree of enhancement to adequately manage aging. Lastly, a number of new inspections were developed to provide objective evidence that aging was, in fact, being adequately managed by the credited programs and activities. The scope of these programs and activities for license renewal is determined by the scope of components and application of programs and activities as defined within the license renewal application and subsequent updates under 10 CFR 54.37(b).

Programs and Activities Credited for Managing Aging in the Renewal Term

It is important to note that only a portion of certain programs or activities may be required to manage aging during the renewal term. Accordingly, only the portion to which a commitment is made in this section is credited for license renewal. The systems, structures and components within the scope of license renewal are those within the evaluation boundaries.

Further, multiple programs or activities may be credited to manage aging in a single system, structure or component. Conversely, there are also cases where one program or activity may manage the effects of aging in multiple systems.

Except where otherwise stated, the portions of programs and activities credited for aging management are applicable to both units. Each management method presented in this section will be characterized as one of the following:

- **Existing Program (Activity):** A current program or activity that will continue to be implemented during the extended license period as shown in Appendix A of the License Renewal Application.
- **Enhanced Program (Activity):** A current program or activity that will be modified to manage aging during the extended license period. Enhancements will be implemented as shown in Appendix A of the License Renewal Application.

- **New Program (Activity):** A program or activity that does not currently exist, which will manage aging during the extended license period. These programs or activities will be implemented for the extended license period as shown in Appendix A of the License Renewal Application.

Characterization of a program or activity as new or existing is self-explanatory. For enhanced programs or activities, the substance of the enhancement is summarized in the text.

Time-Limited Aging Analyses

The Rule requires that time limited aging analyses (TLAA) be evaluated to capture certain plant-specific aging analyses explicitly based on the original 40 year operating life of the plant. In addition, the Rule requires that any exemptions, based on TLAAs, be idenitified and analyzed to justify extension of those analyses through the renewal term.

TLAA evaluations for Plant Hatch included those calculations and analyses that met all six criteria of the Rule, specifically, those calculations or analyses that:

- Involved systems, structures, and components (SSCs) within the scope of license renewal;
- Considered the effects of aging;
- Involved time-limited assumptions defined by the licensed operating term at the time of license renewal application;
- Were determined to be relevant in making a safety determination;
- Involved conclusions or provide the bases for conclusions related to the capability of the SSC to perform its intended functions, as delineated by the Rule; and
- Were contained or incorporated by reference in the licensing basis at the time of application for renewal.

Summary descriptions of TLAAs are provided in section A.4.

A.1 EXISTING PROGRAMS AND ACTIVITIES

Mitigating aging in a boiling water reactor (BWR) is heavily reliant on effective chemistry control and periodic inspection. These activities have been continuously refined at Plant Hatch as new information and techniques have become available.

Consequently, a significant portion of aging management during the renewal term will rely upon existing chemical control and inspection techniques that have evolved throughout the life of the plant, and been proven effective in the initial license term. Other existing programs described in this section are the result of long standing regulatory oversight and Southern Nuclear's involvement in industry improvement efforts.

A.1.1 REACTOR WATER CHEMISTRY CONTROL

A.1.1.1 Description

Reactor water chemistry control is a major part of the overall chemical control strategy for Plant Hatch. It is a mitigating activity designed to maintain structural integrity of plant systems and components by controlling fluid purity and composition.

By controlling water chemistry in the reactor coolant system and other non-inscope systems such as the condensate/feedwater cycle and the reactor water cleanup (RWCU) system, Plant Hatch reduces intergranular stress corrosion cracking (IGSCC) in reactor cooling system piping and reactor internals. Chemistry control also minimizes irradiation-assisted stress corrosion cracking (IASCC) and fuel cladding corrosion. Finally, water chemistry control helps decrease flow-accelerated corrosion (FAC) in the reactor coolant system, as well as balance of plant systems.

The principal elements of reactor water chemistry control are regular sampling, results analysis and, when applicable, chemistry modification. These activities are further supported by trending, tracking, and regular evaluations.

The reactor coolant, condensate, and feedwater systems that normally supply reactor coolant makeup are closely monitored, and regularly sampled and analyzed during all modes of plant operation.

A.1.1.2 Sample Size and Frequency

Reactor water sample frequencies and limits are operating mode dependent. Sample sizes vary in accordance with specific circumstances. The sample parameters and frequencies for each operating mode are specified in plant procedures.

As with reactor water, the specific condensate and feedwater parameters monitored, along with the sample frequencies, vary depending on the plant operational mode.

A.1.1.3 Industry Codes, Standards and Acceptance Criteria

The acceptance criteria for reactor water chemistry control are based upon EPRI BWR water chemistry guidelines.

A.1.1.4 Aging Effects Requiring an Aging Management Program

The aging effects managed by reactor water chemistry control are cracking and loss of material.

Loss of material and cracking are the aging effects mitigated by reactor water chemistry control.

A.1.2 CLOSED COOLING WATER CHEMISTRY CONTROL

A.1.2.1 Description

Closed cooling water (CCW) chemistry control is a mitigating activity intended to maintain structural integrity of plant closed cooling water systems and components by controlling fluid purity and composition.

The in-scope piping and components for license renewal are limited. Included are the section of reactor building closed cooling water (RBCCW) piping that serves the reactor recirculation pump motor bearings and seal coolers inside primary containment, and the primary containment chilled water (PCCW) piping that serves the Unit 2 Drywell Coolers.

The principal elements of CCW chemistry control are chemical additions, regular sampling, results analysis and, when applicable, chemistry modification.

- Chemicals are added to the RBCCW system to inhibit the corrosion process. RBCCW corrosion is monitored by diverting a small amount of flow through a coupon rack in a test loop. Sample coupons are examined periodically to verify the effectiveness of the corrosion inhibitor.
- Biocides are used to control microbiological growth. Chemistry determines which type of microbiocide should be added to the system to ensure that the types of microbiocides used are rotated.

Data are reviewed, and trend analysis is performed. Engineering personnel assist in performing evaluations of the structural integrity of the in-scope plant systems. When necessary, chemistry modification is performed.

A.1.2.2 Sample Size and Frequency

Sampling, operational guidelines, type of treatment, and frequency of analysis are determined by the prevailing fluid conditions.

A.1.2.3 Industry Codes, Standards, and Acceptance Criteria

The framework for CCW chemistry control at Plant Hatch is based upon the guidance provided in EPRI closed cooling water chemistry guidelines. Acceptance criteria contained therein are reflected in plant procedures.

A.1.2.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by CCW chemistry control.

A.1.3 DIESEL FUEL OIL TESTING

A.1.3.1 Description

The Diesel Fuel Oil Testing Program includes activities to mitigate loss of material from diesel fuel oil storage and transfer components that could result from intrusion of water or other contaminants.

The Diesel Fuel Oil Testing Program applies to the emergency diesel generator fuel oil storage tanks, the emergency diesel generator fuel oil day tanks, and the associated transfer piping and components. It also covers the in-scope fire pump diesel fuel oil storage tanks and the associated piping and components.

Fuel oils in their pure form are nonaggressive and noncorrosive for all metals. However, water in fuel oil, naturally occurring contaminants, and fuel oil additives can produce a corrosive environment. Plant Hatch testing activities provide for detection of water or other contaminants before loss of material can threaten a component function. Program elements include sampling new fuel and periodic verification that the total particulate concentration is within acceptable limits.

To prevent introduction of contaminated oil into plant systems, new oil is sampled before off loading the delivery vehicle. An additive is introduced via the transfer hose during the off loading. When properly controlled, this additive minimizes the microorganisms necessary to induce microbiologically influenced corrosion (MIC).

The fire pump fuel oil storage tank and the emergency diesel generator fuel oil storage and day tanks are regularly checked for water in accordance with the FHA and Technical Specifications respectively. If water has accumulated, it is removed.

A.1.3.2 Sample Size and Frequency

Sample sizes and frequencies vary depending upon the circumstances and components being sampled. The significant frequencies and sample sizes are outlined below.

Stored oil total particulate concentration, and water and sediment concentration are sampled once per quarter. Regular surveillance to check for and remove water is completed semi-annually.

A.1.3.3 Industry Codes, Standards and Acceptance Criteria

New oil total particulate concentration sampling prior to off load is conducted using the guidance provided in ASTM D-2276, Method A-2 or A-3, Standard Test Method for Particulate Contaminant in Aviation Fuel.

Other standards applicable to the plant Diesel Fuel Oil Testing Program include, but are not limited to, ASTM D 975-74, Standard Classification of Diesel Fuel Oils; ASTM D 1796-83, Section 5.01, Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (laboratory procedure); and ASTM D 270-65, Part 18, Standard Method of Sampling Petroleum and Petroleum Products.

Total particulate concentration for stored diesel fuel oil is required by Technical Specifications 5.5.9.b, to be less than 10 mg/l. As indicated in SR 2.3.2.b in Appendix B of the FHA, the same acceptance criteria applies to the fire diesel fuel oil storage tank.

A.1.3.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by diesel fuel oil testing.

A.1.4 PLANT SERVICE WATER AND RHR SERVICE WATER CHEMISTRY CONTROL

A.1.4.1 Description

Plant service water (PSW) and residual heat removal service water (RHRSW) chemistry control activities are intended to mitigate aging in system piping and components by controlling fluid composition.

The PSW and RHRSW chemistry control activities are applicable to all system piping/ components within the scope of license renewal, located downstream of the chemical injection points.

The service water system is treated with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) as required.

A.1.4.2 Sample Size and Frequency

Chlorination and bromination are coordinated with the periodic operation of RHRSW to maximize chemical treatment. Normally, each unit's PSW system is chlorinated and brominated separately for 6-12 hours per unit, per day. However, changes in conditions may cause more or less chlorination to be necessary.

A.1.4.3 Industry Codes, Standards and Acceptance Criteria

Since PSW and RHRSW discharge to the circulating water flume, and the flume discharges to the river, chemicals cannot be added at a rate that would cause the National Pollutant Discharge Elimination System (NPDES) permit limit to be exceeded. Although environmental requirements may not necessarily be considered codes or standards, discharged measurable chlorine, free available oxidant, and total residual oxidant levels are governed by the Hatch NPDES permit and, therefore, become the defacto limits to chemistry control in PSW and RHRSW.

A.1.4.4 Aging Effects Requiring an Aging Management Program

Loss of material and flow blockage are the aging effects mitigated by PSW and RHRSW chemistry control.

A.1.5 FUEL POOL CHEMISTRY CONTROL

A.1.5.1 Description

Fuel pool chemistry control activities are intended to mitigate aging in the fuel pool liner and associated components by controlling fluid purity and composition.

The plant fuel pool chemical control activities are applicable to the stainless steel liners for the spent fuel pool, spent fuel pool plugs, spent fuel pool gate, and the refueling canal. Other stainless steel material includes the spent fuel pool storage racks and miscellaneous steel inside the spent fuel pool. Aluminum components include the seismic restraints for the spent fuel storage racks.

The principal elements of the fuel pool chemistry control activities are regular sampling, results analysis and, when applicable, chemistry modification. All chemistry sampling and analysis are done in accordance with approved plant procedures and instructions.

A.1.5.2 Sample Size and Frequency

The fuel pool water is sampled regularly for conductivity, pH, chlorides and sulfates, filterable solids and total organic carbons. The sample frequencies contained in plant procedures are based upon the applicable portions of EPRI guidelines or other updated industry guidance, as they pertain to Plant Hatch.

A.1.5.3 Industry Codes, Standards and Acceptance Criteria

The acceptance criteria contained in plant procedures are based upon EPRI guidelines or other updated industry guidance, as they pertain to Plant Hatch.

A.1.5.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by fuel pool chemistry control.

A.1.6 DEMINERALIZED WATER AND CONDENSATE STORAGE TANK CHEMISTRY CONTROL

A.1.6.1 Description

Demineralized water and condensate storage tank (CST) chemistry control activities are intended to mitigate aging by monitoring fluid purity and composition in the makeup water to multiple systems. The principal elements of these activities are regular sampling, results analysis and, when applicable, chemistry modification.

The demineralized water system proper (P21) is not within the scope of license renewal. However, several systems and components that receive makeup water from the demineralized water storage tank, including the CST, are within the scope of license renewal. Thus, demineralized water storage tank and CST chemistry controls are an important part of overall aging management at Plant Hatch.

A.1.6.2 Sample Size and Frequency

The demineralized water storage tank influent and effluent are monitored. The effluent is sampled weekly for conductivity, pH, silica, chloride, sulfate and total organic carbon. These same parameters are also analyzed for the CST, along with total gamma activity.

A.1.6.3 Industry Codes, Standards and Acceptance Criteria

Plant procedures specify the acceptance criteria for the demineralized water storage tank and CST parameters listed in Section A.1.6.2.

A.1.6.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by demineralized water storage tank and CST chemistry control.

A.1.7 SUPPRESSION POOL CHEMISTRY CONTROL

A.1.7.1 Description

Suppression pool chemistry control activities are intended to mitigate aging in components exposed to the suppression pool water by controlling fluid purity and composition in the pool.

Various components exposed to the suppression pool water are within the scope of license renewal. These include components of the residual heat removal (RHR), core spray (CS), high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) systems and a portion of the safety relief valve (SRV) tailpipes. Also included are the suppression chamber shell, vent header, deflectors and supports, downcomers and braces, and suppression chamber interior platform support.

The principal elements of suppression pool chemistry control activities are regular sampling and results analysis. All chemistry sampling and analysis are done in accordance with approved plant procedures and instructions.

A.1.7.2 Sample Size and Frequency

The suppression pool is sampled regularly for conductivity (zinc corrected), chlorides, sulfates, zinc, and total organic carbons. The sample frequencies contained in plant procedures are based upon the applicable portions of EPRI guidelines or other updated industry guidance.

A.1.7.3 Industry Codes, Standards and Acceptance Criteria

The acceptance criteria contained in plant procedures are based upon EPRI guidelines or other updated industry guidance, as they pertain to chemistry control at Plant Hatch.

A.1.7.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by suppression pool chemistry control.

A.1.8 CORRECTIVE ACTIONS PROGRAM

A.1.8.1 Description

The Corrective Actions Program is briefly described in chapter 17 of the Unit 2 Final Safety Analysis Report (FSAR). This process will be effective for correcting potential age related degradation that may be discovered during the renewal term.

The primary vehicle for initiating corrective action at the plant is the condition reporting process. Existing procedures include the necessary forms and instructions for reporting potential problems related to aging management of the systems, structures and components (SSCs) within the scope of license renewal.

Significant conditions adverse to quality require initiation of a special report. Significant occurrences are investigated to determine root cause, and actions are taken to preclude recurrence. Forms and guidance for root cause analysis are provided in plant procedures or guidelines.

Plant procedures also specify the method for documenting, tracking and correcting reported conditions. Condition reports are analyzed for adverse trends by management. Adverse aging trends during the renewal term can be identified in this manner.

A.1.8.2 Sample Size and Frequency

The Corrective Actions Program applies to the systems, structures and components within the scope of license renewal.

A.1.8.3 Industry Codes, Standards and Acceptance Criteria

Corrective actions are part of the Quality Assurance (QA) Program, as required for the current license term under Criterion XVI of Appendix B to 10 CFR 50. This will continue to be applicable during the renewal term, as modified by the regulatory process.

A.1.8.4 Aging Effects Requiring an Aging Management Program

Each aging effect shown in this appendix is covered by the Corrective Actions Program.

A.1.9 INSERVICE INSPECTION PROGRAM

A.1.9.1 Description

The Inservice Inspection (ISI) Program is a condition monitoring program that provides for the implementation of ASME Section XI in accordance with the provisions of 10 CFR 50.55a at Plant Hatch. The ISI Program also includes augmented examinations required to satisfy commitments made by SNC (e.g., GL-88-01, NUREG-0619). The 10-year examination plan provides a systematic guide for performing nondestructive examination and pressure testing of passive components within the scope of license renewal. Plant Hatch is currently in the third 10-year inspection interval. The period of extended operation will include the fifth and sixth inservice inspection intervals.

The ISI Program provides examination methods and acceptance criteria for Class 1, 2, 3 (equivalent), and Class MC pressure boundary components, as well as the associated supports. It also provides for periodic pressure testing of those same components, along with repair, replacement and modification activities.

ASME Class 1, 2 and 3 (equivalent), and Class MC components are covered by ASME subsections IWB, IWC, IWD, and IWE, respectively. Subsection IWF covers supports, which are treated the same as the code class component they support.

Three types of inspection methods are used for inservice examination at Plant Hatch. They are visual inspections, surface inspections, and volumetric inspections. Visual inspections are performed as defined in IWA-2210. The three types of visual examinations used are designated VT-1, VT-2, and VT-3.

- VT-1 is used to determine the condition of the part, component, or surface examined, including cracks, wear, corrosion, erosion, or physical damage.
- VT-2 is used to locate evidence of leakage from pressure retaining components during a system pressure test.
- VT-3 is used to determine the general mechanical and structural condition of components and the associated supports such as verification of clearances, physical displacements, and loose or missing parts. This includes inspection for debris, corrosion, wear, erosion, or loss of integrity at bolted or welded connections.

Surface examinations are performed as defined in IWA-2220 to determine whether surface cracks or discontinuities exist. Volumetric examinations are performed as defined in IWA-2230 to locate discontinuities throughout the volume of material. These examinations may be conducted from the inside or outside surface of a component. Either radiographic (RT) or ultrasonic examination (UT) methods may be used.

A.1.9.2 Sample Size and Frequency

The extent and frequency of examinations for components subject to ASME Section XI requirements at Plant Hatch are based on the tables in Article 2500 of ASME Section XI Subsections IWB, IWC, IWD, IWE, and IWF.

A.1.9.3 Industry Codes, Standards, and Acceptance Criteria

For the third 10-year inspection interval, Plant Hatch uses the 1989 Edition of ASME Section XI for Class 1, Class 2, and Class 3 (equivalent) systems and components. For Class MC systems and components, Plant Hatch applies the 1992 Edition of ASME Section XI with the 1992 addenda. The acceptance standards used for inservice inspection are based on the tables in Article 2500 of ASME Section XI Subsections IWB, IWC, IWD, IWE, and IWF.

A.1.9.4 Aging Effects Requiring an Aging Management Program

Loss of material, cracking, loss of preload, and loss of fracture toughness are the aging effects monitored by the ISI Program.

A.1.10 OVERHEAD CRANE AND REFUELING PLATFORM INSPECTIONS

A.1.10.1 Description

Plant crane and refueling platform inspections are condition monitoring activities conducted to verify structural integrity of all load bearing and operating components to assure safe operation. Crane and refueling platform inspection activities also satisfy the requirements of the Unit 1 Technical Requirements Manual which requires surveillance testing of the 5-ton hoist, and the crane/hoist used for handling fuel assemblies or control rods.

Inspection activities include a preoperational static inspection, preoperational dynamic inspection, operational inspection, maintenance inspection, and as required inspections. The overhead crane and refueling platform hoist, rigging, slings and lifting devices are visually inspected to ensure structural integrity. A trial lift of the spent fuel pool gate or an equivalent weight is also performed for each device performing this lifting function.

When cranes are in service, or prior to using standby cranes, detailed visual inspection of all wire rope is made to check for, among other things, general corrosion, kinks, and strand displacement. Hooks are visually inspected for cracks or distortion. Connections are checked for weld cracks and loose or missing bolts. Bridges, bridge rails, trolley and trolley rails are visually inspected for straightness and evidence of physical damage or cracking.

A.1.10.2 Sample Size and Frequency

All load bearing and crane operating components within the scope of license renewal are inspected. General visual inspections are performed monthly in accordance with plant procedures. Annual magnetic particle tests are performed on hooks. Overhead cranes are visually inspected daily when in use.

A.1.10.3 Industry Codes, Standards and Acceptance Criteria

Plant overhead crane and refueling platform inspection procedures were developed using ANSI B30.2.0-1976 and NUREG-0612. Inspection procedures for fuel handling equipment were developed using ANSI B30.9-1971, ANSI/ASME B30.10-1982, ANSI N14.6-1978 and NUREG-0612. Wire rope safety factors from ANSI B30.5 or SAE J959-1966 are applied to acceptance criteria.

End connections must not be severely corroded, cracked, bent, worn or improperly applied. Wire rope must be within the maximum reduction from nominal as stated in plant procedures. Any weld cracking requires performance of nondestructive testing. Loose bolts are replaced rather than tightened.

A.1.10.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect monitored by plant crane inspections.

A.1.11 TORQUE ACTIVITIES

A.1.11.1 Description

Torque activities are intended to mitigate loss of preload through use of proper torque techniques at Plant Hatch. Plant procedures provide specific instructions for maximizing the effectiveness of torque activities.

Hardened steel washers may be used in conjunction with joint bolting, since they allow more of the applied torque to be translated to bolt stress, which provides the preload necessary for a tightly sealed joint. In joints subject to thermal or process load cycling, Belleville washers or extra-length bolting may be used to provide better response to the changing conditions caused by cycling.

Bolting threads and load bearing faces are lubricated with an approved thread lubricant immediately before assembly to allow the maximum torque to be translated to bolt stress. Leveling passes are performed using a calibrated torquing tool and continue until there is no rotational movement of the fasteners at the final torque value.

For any joint considered at high risk for leakage, as demonstrated by past performance or based on the judgment of the responsible supervision, leveling passes may be repeated at the final torque value after 24 hours. This may be done to compensate for gasket relaxation (creep) prior to putting the joint into service.

A.1.11.2 Sample Size and Frequency

The Plant Hatch torquing procedure was developed for use on pressure retaining systems, ASME Code piping, and other fasteners used in bolted joints where satisfactory torque values are not available in other approved plant documents.

A.1.11.3 Industry Codes, Standards and Acceptance Criteria

The torquing procedure was evaluated against the guidance contained in EPRI guidelines for degradation and failure of bolting in nuclear power plants.

Other codes and standards considered during development of the plant torquing procedure were ASME, Section VIII, Div. 1, App. 2; ASME, Section II, Specification for Carbon Steel Externally Threaded Standard Fasteners; ASTM Standards, Section 15, Volume 15.08, Fasteners; and ANSI B31.1.

A.1.11.4 Aging Effects Requiring an Aging Management Program

Loss of preload is the aging effect mitigated by torque activities.

A.1.12 COMPONENT CYCLIC OR TRANSIENT LIMIT PROGRAM

A.1.12.1 Description

The Plant Hatch Component Cyclic or Transient Limit Program is a surveillance program required by Technical Specifications. It is designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components and the torus will remain within the ASME Code Section III fatigue limits, including the effects of a reactor water environment.

The plant fatigue cumulative usage factor (CUF) is calculated for four limiting high stress reactor pressure vessel (RPV) boundary components on each unit. The RPV main closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles have been shown by analysis to be the limiting components.

CUF is also calculated for the limiting location for the torus on each unit, and for nine locations within the Class 1 boundary. Class 1 monitoring includes the limiting locations on the reactor vessel equalizer, core spray, standby liquid control, feedwater, HPCI, RCIC, RWCU, and main steam piping for Unit 1. On Unit 2, the limiting locations are the residual heat removal, feedwater, primary steam condensate drainage, and main steam piping.

When CUF calculations project CUF to exceed 1.0 for the next operating cycle, engineering evaluations are performed to disposition the projection.

A.1.12.2 Sample Size and Frequency

Plant procedures require that the CUF for each of the limiting components on each unit be calculated at least once per operating cycle. Data may be collected at any time during the surveillance period.

A.1.12.3 Industry Codes, Standards and Acceptance Criteria

High fatigue usage components have been selected to be tracked by this program to assure that the plant will continue to meet the ASME Code, Section III, CUF design requirement value of 1.0.

A.1.12.4 Aging Effects Requiring an Aging Management Program

Cracking is the aging effect monitored by the Component Cyclic or Transient Limit Program.

A.1.13 PLANT SERVICE WATER AND RHR SERVICE WATER INSPECTION PROGRAM

A.1.13.1 Description

The Plant Service Water (PSW) and RHR Service Water (RHRSW) Inspection Program is a condition monitoring program. This program is designed to detect wall thickness degradation or fouling in the PSW and RHRSW systems. Locations determined to be prone to corrosion are infrequently used piping, piping with low fluid velocity, small diameter piping, backing rings and socket welds. Locations prone to clogging include those prone to corrosion, horizontal runs of piping at the bottom of vertical runs, intermittently used piping, and low point drains.

Piping inspections may be performed using radiography testing (RT), ultrasonic testing (UT), depth gauges or pipe removal and analysis.

A.1.13.2 Sample Size and Frequency

The inspection frequencies are determined by evaluating the trends in wall thickness reduction. If the trend indicates that the pipe wall thickness might be reduced to the minimum allowable wall thickness value prior to completion of the next operating cycle, then the inspection frequency and lot size are adjusted. In all cases, at least one full operating cycle must be allowed to complete repairs prior to reaching the minimum pipe wall thickness.

A.1.13.3 Industry Codes, Standards and Acceptance Criteria

The PSW and RHRSW Inspection Program was developed using the edition of ASME, Section XI in the Inservice Inspection Program. Although not specifically codes or standards, the framework for the program is also based partially upon Generic Letter 89-13 and its supplements, and NUREG-1275, Volume 3, “Operating Experience Feedback Report – Service Water System Failures and Degradations”.

Minimum wall thickness is calculated in accordance with the piping design code, piping stress requirements and the piping specification drawings. The bases for the acceptance criteria are contained in the PSW and RHRSW Inspection Program procedures.

A.1.13.4 Aging Effects Requiring an Aging Management Program

Loss of material, flow blockage, cracking, and loss of heat exchanger performance are the aging effects monitored through the PSW and RHRSW Inspection Program.

A.1.14 PRIMARY CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A.1.14.1 Description

The Plant Hatch Primary Containment Leakage Rate Testing Program is a condition and performance monitoring program that ensures the structural integrity of primary containment through visual inspection and performance testing activities. Plant Hatch Technical Specifications require the implementation of the Primary Containment Leakage Rate Testing Program and the attendant written procedures.

This program applies to all 10 CFR 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. This includes the steel primary containments, containment penetrations, and containment internal structures which perform a structural or pressure retaining function. It also includes the steel and nonferrous components of the containment airlocks, equipment hatches, and control rod drive (CRD) removal hatches.

Type A tests are performed in accordance with ANSI/ANS 56.8 1994 and/or Bechtel Topical Report BN-TOP-1 and implemented through plant procedures. Type B and C tests are performed in accordance with ANSI/ANS 56.8-1994 and implemented through plant procedures.

A.1.14.2 Sample Size and Frequency

Test frequencies are determined in accordance with plant procedures. An as-found Type B or C test is performed prior to any maintenance, repair, modification, or adjustment activities that could affect the primary containment boundary's leak tightness.

A.1.14.3 Industry Codes, Standards and Acceptance Criteria

The Primary Containment Leakage Rate Testing Program is based upon Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," September 1995. ANSI/ANS-56.8-1994, "American National Standard for Containment System Leakage Testing Requirements," 1994, and NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J", July 26, 1995 are also used.

The primary containment leakage rate acceptance criteria for the Plant Hatch Primary Containment Leakage Rate Testing Program are specified in the Technical Specifications. The administrative limits assigned to each component are specified such that they are indicators of potential penetration degradation.

A.1.14.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect monitored by the Primary Containment Leakage Rate Testing Program.

A.1.15 BOILING WATER REACTOR VESSEL AND INTERNALS PROGRAM

A.1.15.1 Description

The Boiling Water Reactor Vessel and Internals Project (BWRVIP) is an association of utilities formed to focus on resolution of BWR vessel and internals issues. The BWRVIP Program was developed based on over 20 years of service and inspection experience and is focused on detecting evidence of component degradation well in advance of significant degradation.

For license renewal, the BWRVIP Program inspection and evaluation reports specifically addressed the internals relative to the requirements of the Rule. At the time of the Plant Hatch LRA, the NRC was continuing its review of these reports and issuing safety evaluation reports (SERs) to address license renewal.

The BWRVIP Program reviewed the function of each internal BWR component. For those internals that could impact safety, the BWRVIP Program considered the mechanisms that might cause degradation of such components and developed an inspection program that would enable degradation to be detected before the component function was adversely affected.

The reactor vessel internals requiring aging management within the scope of license renewal are the shroud, shroud supports, core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, and dry tubes. For Unit 1 only, the top guide is also included.

The reactor internals are examined using a combination of ultrasonic, visual, and surface methods. The methods to be used and the frequency of examination will be as specified in the applicable inspection and evaluation document, unless specific exception has been identified to the NRC.

SNC has evaluated the BWRVIP Program for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV components, including the materials used for construction, are addressed by the BWRVIP Program inspection and evaluation documents. The plant operation parameters, including temperature, pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

- The components, which require aging management review in accordance with the Rule, are covered by the BWRVIP Program reports.
- The BWRVIP Program reports cover all Hatch internals design.

Therefore, SNC has established that the BWRVIP Program reports bound the Hatch Units 1 and 2 design and operation.

A.1.15.2 Sample Size and Frequency

The frequency of examination varies for each component or subassembly. The frequency is based on the component's design, flaw tolerance, susceptibility to degradation, and the method of examination used. In cases where a component may be inspected using either visual or ultrasonic methods, the interval between examinations is shorter when visual methods are used.

A.1.15.3 Industry Codes, Standards, and Acceptance Criteria

The requirements of Section XI of the ASME Boiler and Pressure Vessel Code apply to attachments welded to the RPV, welded core support structures, and penetrations. In most cases, the BWRVIP Program is more appropriate than Section XI requirements for use on BWR internals.

The BWRVIP Program for internals subject to license renewal as implemented at Plant Hatch employs the BWRVIP Program criteria documented in the NRC SERs, except where specific exception has been identified to the NRC.

A.1.15.4 Aging Effects Requiring an Aging Management Program

Cracking is the aging effect managed by the BWRVIP Program.

A.1.16 WETTED CABLE ACTIVITIES

A.1.16.1 Description

Plant Hatch wetted cable activities provide for mitigating activities as well as condition monitoring activities. Plant Hatch wetted cable activities include monitoring for and removing water, along with testing to detect changes in insulation resistance. Several 4 kV power cables and transformer feeder cables within the scope of license renewal are routed through the underground duct bank system consisting of outdoor pull boxes containing underground conduits routed between in-scope buildings.

In pull boxes where these in-scope cables are routed, water level is measured, recorded, and the pull boxes drained. Megger and polarization index (PI) testing are periodically performed. The cables are hipot tested when new terminations are made. This provides additional assurance that the cable insulation integrity is sound.

A.1.16.2 Sample Size and Frequency

Pull boxes are drained quarterly. Testing is performed on inscope 4-kV motor windings and the associated feeder cables during regular motor and pump maintenance tasks.

A.1.16.3 Industry Codes, Standards and Acceptance Criteria

The activities described herein meet the intent of IEEE 43-1974, Recommended Practice for Testing Insulation Resistance of Rotating Machinery; and IEEE 95-1977, Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage.

Pull boxes found to contain water are drained to 1 inch of water or less. Cables and loads must successfully pass megger and PI testing.

A.1.16.4 Aging Effects Requiring an Aging Management Program

Change in insulation resistance is the aging effect mitigated and monitored by the wetted cable activities.

A.1.17 REACTOR PRESSURE VESSEL MONITORING PROGRAM

A.1.17.1 Description

Reactor Pressure Vessel (RPV) Monitoring Program is an existing condition monitoring and surveillance program at Plant Hatch. It is based on detailed evaluation of the Plant Hatch Unit 1 and Unit 2 RPVs. The program is supported by an industry topical report for the license renewal period, BWRVIP-74, which is under review by the Nuclear Regulatory Commission (NRC) at the time of the license renewal application.

The RPV Monitoring Program covers the reactor vessel beltline shells, feedwater nozzles, core spray nozzles, control rod drive return line nozzle, recirculation inlet and outlet nozzles, jet pump instrumentation nozzles, and penetration seals. The core dP and standby liquid control nozzle, the support skirt and the closure studs, the core spray pipe, jet pump riser brace pad, and shroud support welds are also included.

RPV monitoring is accomplished through a combination of fatigue monitoring, code-required and augmented inspections, pressure tests, and surveillance material testing. RPV shell and head aging management is accomplished by performing ultrasonic examinations of the RPV vertical shell welds, periodic pressure tests with visual examination for leakage, and surveillance capsule testing. Plant Hatch uses an NRC approved technical alternative in lieu of ultrasonic testing of circumferential shell welds. This basis for the alternative is contained in the BWR reactor pressure vessel shell weld inspection recommendations, and associated supplements.

The Plant Hatch materials surveillance program may be altered prior to operation during the renewal period. The BWRVIP is developing an Integrated Surveillance Program (ISP) for all domestic operating BWRs as allowed by 10 CFR 50 Appendix H. The ISP will be provided to the NRC by BWRVIP for review and approval. Both Hatch RPVs are included in the program. However, existing analyses at the time of application show that operation to 60 years is acceptable.

SNC has evaluated the BWRVIP program for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operation parameters, including temperature pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

- The components, which require aging management review in accordance with the Rule, are covered by the BWRVIP reports.
- The BWRVIP reports cover all Hatch internals design.

Therefore, SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design and operation.

A.1.17.2 Sample Size and Frequency

RPV vertical shell welds are examined once every 10 years. A pressure test of the RPV is conducted at the end of each refueling outage.

RPV nozzles and safe ends are examined as required by ASME Section XI or an augmented program, in accordance with the Plant Hatch ISI Program (Section A.1.9). This includes ultrasonic and surface examinations for nozzles 4 nominal pipe size (NPS) and larger, surface examination for nozzles less than 4 NPS. Pressure tests for the Class 1 boundary are performed at the conclusion of each refueling outage in accordance with ASME Section XI, Section IWB-5000.

A.1.17.3 Industry Codes, Standards, and Acceptance Criteria

RPV ultrasonic examinations and the pressure tests with the associated visual examinations will be conducted in accordance with ASME Section XI as part of the Inservice Inspection (ISI) Program that is required by 10 CFR 50.55a (see Section A.1.9). RPV surveillance capsule testing is required by 10 CFR 50 Appendix H. That testing provides data used to show that the criteria for fracture toughness of 10 CFR 50 Appendix G are satisfied.

Limits are imposed on pressure and temperature by 10 CFR 50 Appendix G. Pressure-Temperature limit curves have been prepared for Hatch Units 1 and 2 to allow operation up to 54 EFPY. Appendix G of 10 CFR 50 also contains requirements for Upper Shelf Energy (USE) to ensure adequate fracture toughness is maintained. USE calculations performed for Plant Hatch limiting beltline materials, using equivalent margins analysis, justify operation up to 54 EFPY.

Feedwater nozzles will be examined in accordance with ASME Section XI and the Plant Hatch NUREG-0619 Program (see Section A.1.9). The recirculation inlet nozzles and the feedwater nozzles are covered by the fatigue monitoring program (see Section A.1.12).

A.1.17.4 Aging Effects Requiring an Aging Management Program

Cracking and loss of fracture toughness are the aging effects monitored by the RPV Monitoring Program.

A.2 ENHANCED PROGRAMS AND ACTIVITIES

During the aging management reviews, Southern Nuclear found cases where opportunities existed for aging management improvements. While enhancements will serve to better manage aging at Plant Hatch, no cases were found where immediate action was required to maintain the license renewal functions.

The enhancements for the affected programs or activities are outlined in this section under the appropriate description. These enhancements may be implemented on or before the dates indicated under each description.

A.2.1 FIRE PROTECTION ACTIVITIES

A.2.1.1 Description

Fire protection activities are comprised of condition monitoring and performance monitoring activities. Fire protection activities provide assurance that a fire will not prevent the performance of necessary safe shutdown functions. Through a defense-in-depth philosophy, the Fire Protection Program is designed to minimize both the probability and consequences of postulated fires.

The portion of the Plant Hatch fire protection activities credited for license renewal is that portion included in Appendix B of the Fire Hazards Analysis (FHA). It includes passive long-lived components in water based and gaseous fire suppression systems. Also included are the fire pump diesel fuel oil supply system (tanks and piping) and various fire rated assemblies.

The water-based fire protection header loop piping is flushed on a regular basis. The fire pump casings are visually inspected and operationally tested. Sprinklers are visually inspected and open-head sprinklers and nozzles are flow tested using air.

Fire water tank internals are inspected for localized and general pitting, average dry film thickness and general condition of the protective coating. Sizes and depth of pits are recorded. Interior surfaces are cleaned as required to facilitate inspection.

The fire pump diesel fuel oil supply and various gaseous fire suppression system components are visually inspected and performance tested. The in-scope fire-rated assemblies are also visually inspected periodically.

A.2.1.2 Sample Size and Frequency

The surveillance requirements and the associated frequencies are set forth in Appendix B of the FHA.

A.2.1.3 Industry Codes, Standards and Acceptance Criteria

The fire protection system at the plant was designed in accordance with the requirements of Nuclear Electric Insurance Limited (NEIL). The design was reviewed against the applicable NFPA codes, and the local codes and regulations applicable to Plant Hatch have been met.

A.2.1.4 Aging Effects Requiring an Aging Management Program

Loss of material, cracking, flow blockage, and change in material properties in nonmetallic components are the aging effects monitored by fire protection activities.

A.2.1.5 Enhancements

Fire protection activities will be enhanced to include periodic inspection of water suppression system strainers which will be inspected for flow blockage and loss of material due to mechanisms such as corrosion.

Enhancements will be implemented by midnight August 6, 2014.

A.2.2 FLOW ACCELERATED CORROSION PROGRAM

A.2.2.1 Description

The Flow Accelerated Corrosion (FAC) Program is a condition monitoring program designed to monitor pipe wear in those systems that have been determined to be susceptible to FAC-related loss of material. Piping that may be susceptible to FAC is predicted using a model specifically developed for FAC analysis.

The FAC model predicts single- and two-phase flow-accelerated corrosion rates in piping, and calculates the time remaining until reaching the defined critical wall thickness. Large bore piping modeled for FAC includes the reactor feedwater piping. Several sections of piping are also inspected based upon industry experience.

Ultrasonic testing (UT) is used to detect wall thinning. Radiographic testing (RT) may be used in cases where UT is impractical (e.g., small-diameter piping). In certain cases, visual examinations (VT) from inside the piping may be performed, with followup UT contingent upon the VT results.

A.2.2.2 Sample Size and Frequency

Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical modeling results, pertinent industry events, and plant operating experience.

A.2.2.3 Industry Codes, Standards and Acceptance Criteria

The framework for the Plant Hatch FAC Program is based upon EPRI recommendations for effective flow-accelerated corrosion program. The equations used to derive wall thickness acceptance criteria are based upon the governing code of record for the piping.

A.2.2.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect monitored by the FAC Program

A.2.2.5 Enhancements

The enhanced examination methods and frequencies will be based on industry and plant-specific operating experience as opposed to computer modeling. Examinations to detect erosion, erosion corrosion, as well as FAC, will be performed as part of the enhanced program.

For both units, the Flow Accelerated Corrosion Program will be expanded to include additional piping for certain systems that are already included in the current program.

For Unit 2 only, portions of the radioactive decay holdup volume (main steam and steam line drains, and condensate drains) will also be included.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

A.2.3 PROTECTIVE COATINGS PROGRAM

A.2.3.1 Description

The Protective Coatings Program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance and inspection of protective coatings on selected components and structures.

A.2.3.2 Sample Size and Frequency

Protective coatings surveillance is normally performed once per operating cycle for Service Level I components. Other component surveillance is performed as determined by the protective coatings specialist, based upon trends and plant specific operating experience.

A.2.3.3 Industry Codes, Standards and Acceptance Criteria

Multiple codes and standards were considered in the development of the plant Protective Coatings Program. These include ANSI N5.12 – 1972, Protective Coatings (Paints) for the Nuclear Industry; ANSI N101.2 – 1972, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities; ASTM, Section 6, Volume 06.02, Paints-Products and Applications, Protective Coatings, Pipeline Coatings, and AWWA C209, American Waterworks Association Code for Cold Applied Tape Coatings.

Coatings application is not allowed to proceed until applicable solvent cleaning, removal of stratified rust, loose mill scale, nonadherent paint, weld flux and splatter, and thick edge paint feathering has been verified. Prepared steel must conform to SSPC-SP11 (Steel Structures Painting Council) visual standards SSPC-VIS3, or equivalent.

A.2.3.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated and monitored by the Protective Coatings Program.

A.2.3.5 Enhancements

The Protective Coatings Program will be expanded to include the external surfaces of carbon steel commodities in-scope for License Renewal that are exposed to inside, outside, submerged, and buried environments as made accessible. Portions of multiple systems will be included, based upon plant-specific operating experience and conditions.

Affected systems will include, but may not be limited to, the nuclear boiler, standby liquid control, residual heat removal, residual heat removal service water, core spray, high pressure coolant injection and reactor core isolation cooling. Certain portions of the-post accident radioactive decay holdup, plant service water, instrument air, drywell chilled water, drywell pneumatics, standby gas treatment, nitrogen inerting, fire protection, diesel fuel oil, piping supports, raceway supports, and building structural steel will also be included. The affected components in these systems will be piping, valves, pumps, bolts, tanks, and structural steel components.

The Protective Coatings Program will be revised to require periodic inspections of in-scope components to ensure that they are properly coated and free of significant age-related degradation. Coated surfaces of certain components, including those normally inaccessible but made accessible due to maintenance or other activities, will also be inspected when they become accessible.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common system components, and midnight June 13, 2018 for Unit 2.

A.2.4 EQUIPMENT AND PIPING INSULATION MONITORING PROGRAM

A.2.4.1 Description

The Equipment and Piping Insulation Monitoring Program at Plant Hatch is a condition monitoring program designed to detect insulation damage, as well as provide for inspection of specific component insulation located in outside environments.

Plant maintenance program procedures contain limitations to climbing on pipe insulation unless specifically justified by an engineering review and evaluation. Procedures also provide specific instructions for removal, storage and installation of thermal and reflective insulation.

A.2.4.2 Sample Size and Frequency

Outside insulation within the scope of license renewal is currently inspected annually.

A.2.4.3 Industry Codes, Standards and Acceptance Criteria

Plant procedures specify the acceptance criteria for the equipment and piping insulation, including insulation jackets.

A.2.4.4 Aging Effects Requiring an Aging Management Program

Cracking, loss of material, and change in material properties are the aging effects monitored by the Equipment and Piping Insulation Monitoring Program.

A.2.4.5 Enhancements

The Equipment and Piping Insulation Monitoring Program will be expanded to include in-scope portions of inside equipment and piping insulation. Insulation will be periodically examined for holes, tears, compaction, and material separation, wetting, missing insulation and general deterioration, using appropriate visual inspection techniques. Aluminum and galvanized steel insulation jackets and their binders will be visually inspected for cracking and loss of material.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common system components, and midnight June 13, 2018 for Unit 2.

A.2.5 STRUCTURAL MONITORING PROGRAM

A.2.5.1 Description

The Plant Hatch Structural Monitoring Program (SMP) provides condition monitoring and appraisal of certain important structures and structural components. The program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program.

The covered structures within the scope of license renewal include the reactor buildings, turbine buildings, intake structure, main stack, diesel generator building, and control building. The condensate storage tank foundations and walls, plant service water valve pits, and nitrogen storage tank foundations are also examined. When practical, digital photography is used to document degradation found.

Structural inspections are primarily visual. Inspected structures include those normally accessible, as well as those below ground or embedded. When normally inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed.

A.2.5.2 Sample Size and Frequency

The inspection frequency for plant structures varies according to site conditions and susceptibility to aging degradation. Structures monitored under the provisions of 10 CFR 50.65 (a)(2) are inspected every five operating cycles, unless the conditions, environment, or noted degradation warrant increased frequency. The intake structure is currently inspected every outage because of the humid environmental conditions.

A.2.5.3 Industry Codes, Standards and Acceptance Criteria

The framework for the SMP is consistent with industry guideline NEI 96-03. The NEI 96-03 guidance was conditionally accepted in Regulatory Guide 1.160.

The SMP and supporting programs specify acceptance criteria for structural inspection and evaluation. The acceptance criteria are based upon ACI 349.3R-1996, but also include additional criteria for roof ponding, water leakage, coatings and penetration seals. The SMP acceptance criteria are consistent with NEI-96-03 and NRC Regulatory Guide 1.160, revision 2.

A.2.5.4 Aging Effects Requiring an Aging Management Program

Loss of material, cracking, flow blockage, and material property changes are the aging effects monitored by the Structural Monitoring Program.

A.2.5.5 Enhancements

The scope of the SMP will be expanded to include visual inspections of the following structures and components:

- Sealants in the joints between the reactor building exterior precast siding panels.

- Seismic Category I and Seismic Category II/I piping supports and tube tray supports.
- Seismic Category I HVAC duct supports.
- Seismic Category I and Seismic Category II/I cable trays and cable tray supports.
- Seismic Category I and Seismic Category II/I conduits and conduit supports.
- Seismic Category I Control room panels, racks and supports.
- Seismic Category I Auxiliary panels, racks and supports.
- Reactor building tornado vents.

The frequency of enhanced visual inspections will be based on specific plant experience, commensurate with prudent concern for adequately managing aging. Additional emphasis will be placed on the importance of inspecting and documenting the condition of normally inaccessible (underground or embedded) structures.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common structural components, and by midnight June 13, 2018 for Unit 2.

A.3 NEW PROGRAMS AND ACTIVITIES

New programs or activities were primarily driven by a lack of documented evidence to show that the credited mitigation or prevention activities would be effective into the renewal term. Therefore, for the most part, the new programs and activities are intended to provide objective evidence of the effectiveness of the programs and activities credited for aging management during the renewal term.

New programs or activities will be purposefully delayed until near the end of the current license period (i.e., the last 5 years of the original design life). This will allow assessment of the effectiveness of mitigating or preventive aging management activities and documentation of the original design life condition of the systems being inspected.

A.3.1 GALVANIC SUSCEPTIBILITY INSPECTIONS

A.3.1.1 Description

The Plant Hatch Galvanic Susceptibility Inspections will provide for condition monitoring via one time inspections that will provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal.

Since galvanic corrosion is most likely in commodities within environments that are more corrosive (high impurity and conductivity levels), these inspections will start with the more corrosive raw water environment. Galvanic Susceptibility Inspections will examine a sample population of carbon to stainless steel weld connections that should exhibit the largest galvanic coupling. If the examined carbon to stainless welds show galvanic corrosion, the sample set will be expanded to other water systems.

Piping inspections will be performed using one or more methods. These may include ultrasonic thickness determinations, radiographic testing, depth gauges, and pipe removal and analysis.

A.3.1.2 Sample Size and Frequency

The sample set will be selected from raw water carbon to stainless weld connections following issuance of the new operating license. Examination results will be evaluated to determine whether the sample set should be expanded to other environments. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

A.3.1.3 Industry Codes, Standards and Acceptance Criteria

Inspection procedures and acceptance criteria will be developed using the applicable sections of the ASME Code and applicable industry practices.

Where applicable, minimum wall thickness will be calculated in accordance with the piping design code, piping stress requirements, and the piping specification drawings. The acceptance criteria will be contained in the inspection procedures.

A.3.1.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect that will be monitored by the Galvanic Susceptibility Inspections.

A.3.2 TREATED WATER SYSTEMS PIPING INSPECTIONS

A.3.2.1 Description

The plant Treated Water Systems Piping Inspections will provide for condition monitoring via one time examinations intended to provide objective evidence that existing Chemistry Control is managing aging in piping that is not examined under another inspection program.

Treated Water System Piping Inspections will examine a sample population of carbon and stainless steel tubing and piping in the treated water systems. The results of the sample population examinations will be recorded and evaluated, and subsequent examinations will be conducted where evaluation results warrant. If significant degradation is noted, the sample set may be expanded.

Inspections will be conducted using techniques appropriate for piping examination and trending. This may include, but not be limited to, volumetric or destructive examination. The specific sample population, examination methods and acceptance criteria will be defined in the inspection and trending procedures.

A.3.2.2 Sample Size and Frequency

For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018. Subsequent examinations may be conducted on a frequency determined by an engineering evaluation of inspection results.

A.3.2.3 Industry Codes, Standards and Acceptance Criteria

A one-time visual inspection of the sample set will be conducted using the best available examination method for the inspected component. Mechanical joints may be inspected using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Where possible and practical, accessible components may be inspected using volumetric examination methods. Specific inspection criteria will be identified in the inspection procedure(s).

A.3.2.4 Aging Effects Requiring an Aging Management Program

Cracking and loss of material are the aging effects that will be monitored by the Treated Water Systems Piping Inspections.

A.3.3 GAS SYSTEMS COMPONENT INSPECTIONS

A.3.3.1 Description

Plant Hatch Gas Systems Component Inspections will provide for condition monitoring via one time condition monitoring aging management activities designed to provide objective evidence that the aging effects predicted for systems with gases as internal environments are being adequately managed.

Gas Systems Component Inspections will span several systems within the scope of license renewal. Humid and wetted gas internal environments at various temperatures will be inspected.

Procedures will be developed to examine the internal surfaces of a sample population of low points and other susceptible locations in the applicable system components. The Gas Systems Component Inspection activities will use examination techniques designed to ascertain whether significant loss of material or cracking has occurred in the sample population.

A.3.3.2 Sample Size and Frequency

The sample population will include areas of gas bearing piping and ductwork that have the potential for liquid pooling, wet/dry cycling, or thermal degradation. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

A.3.3.3 Industry Codes, Standards and Acceptance Criteria

A one-time visual inspection of the sample set will be conducted using the best available examination method for the inspected component. Mechanical joints may be inspected using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Where possible and practical, accessible components may be inspected using volumetric examination methods. Specific inspection criteria will be identified in the inspection procedure(s).

A.3.3.4 Aging Effects Requiring an Aging Management Program

Loss of material, material property changes, and cracking are the aging effects that will be monitored by the Gas Systems Component Inspections.

A.3.4 CONDENSATE STORAGE TANK INSPECTION

A.3.4.1 Description

The plant Condensate Storage Tank (CST) Inspections will provide for condition monitoring via one time inspections intended to provide objective evidence that the aging effects predicted for the CST internal environments are adequately managed by programs credited for the renewal term.

Internal surfaces of each CST will be examined to verify that age-related degradation is not occurring. The examination will focus on the standpipes and the connections between aluminum standpipes and galvanized steel flanges, since these locations would be the most susceptible to corrosion.

A.3.4.2 Sample Size and Frequency

There will be a one-time inspection of each CST. Southern Nuclear anticipates the inspections will be completed coincident with other scheduled CST maintenance. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

A.3.4.3 Industry Codes, Standards and Acceptance Criteria

Visual inspection of each CST will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Specific inspection criteria will be identified in the inspection procedure(s).

A.3.4.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect that will be monitored by the CST Inspections.

A.3.5 PASSIVE COMPONENT INSPECTION ACTIVITIES

A.3.5.1 Description

The passive component inspection activities will be a new condition monitoring aging management activity at Plant Hatch. These inspections will be designed to collect, report and trend age-related data. This activity will verify the effectiveness of preventive or mitigative programs/activities credited for aging management.

In addition to piping, this activity will include the internal and external surfaces of other passive components such as valve bodies, ducting, and strainers. These will be components that are within the scope of license renewal, but which are exempt from ASME Section XI and Generic Letter 88-01 inspections, or other regulatory requirements.

Plant procedures or directives will be developed to require that the selected inscope components be examined. These documents will contain specific inspection criteria and will require recording inspection results.

Plant procedures will include requirements to ensure that inspection results are reviewed, evaluated, and trended. Subsequent inspection frequencies will be determined by the trends in age-related degradation discovered during the inspections.

A.3.5.2 Sample Size and Frequency

Once this activity has been implemented, Southern Nuclear anticipates that baseline inspections will begin for the selected components as those components are made accessible due to normal maintenance activities. The baseline inspections may be done at any time. The activity will be fully implemented no later than midnight August 6, 2014 and midnight June 13, 2018 for Units 1 and 2, respectively.

A.3.5.3 Industry Codes, Standards and Acceptance Criteria

Visual inspection of each component will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Liquid penetrant (PT) examination, or other suitable method dictated by the situation for the affected component, may be used to detect discontinuities open to the component surface. Specific inspection techniques and acceptance criteria will be contained in the inspection procedure(s).

A.3.5.4 Aging Effects Requiring an Aging Management Program

Loss of material and cracking are the aging effects that will be monitored by the passive component inspection activities.

A.3.6 RHR HEAT EXCHANGER AUGMENTED INSPECTION AND TESTING PROGRAM

A.3.6.1 Description

The Plant Hatch Residual Heat Removal (RHR) Heat Exchanger Augmented Inspection and Testing Program is a condition monitoring program that will provide enhanced aging management of both the shell and tube sides of the Unit 1 and Unit 2 RHR heat exchangers. The RHR heat exchangers will be visually inspected, and eddy current testing will be done on a regular basis.

A.3.6.2 Sample Size and Frequency

The RHR Heat Exchanger Augmented Inspection and Testing Program will be fully implemented no later than midnight August 6, 2014 and midnight June 13, 2018 for Units 1 and 2, respectively.

Thereafter, RHR heat exchanger partition plates will be visually inspected once every 54 months. Eddy current testing will be performed on the tubes at least once during each 10-year inspection interval, and whenever leaks are suspected in tubes and/or the tube sheet. The shell side of the tube sheets, shell internals and impingement plates will be visually inspected once per 10-year inspection interval, where accessible. Tube and tube sheet leak testing will be performed whenever leaks are suspected.

A.3.6.3 Industry Codes, Standards and Acceptance Criteria

Visual inspections will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210, or other suitable method, as dictated by the situation. Specific inspection techniques and acceptance criteria will be contained in the inspection and testing procedure(s).

A.3.6.4 Aging Effects Requiring an Aging Management Program

Loss of material, loss of heat exchanger performance, and cracking are the aging effects that will be monitored by the RHR Heat Exchanger Augmented Inspection and Testing Program.

A.3.7 TORUS SUBMERGED COMPONENTS INSPECTION PROGRAM

A.3.7.1 Description

The Torus Submerged Components Inspection Program is a condition monitoring activity that will provide a means for evaluating the effectiveness of the current suppression pool chemistry control in preventing loss of material and cracking in the components within the scope of license renewal.

Torus submerged components inspections will be conducted on accessible components submerged in suppression pool water, including the emergency core cooling system (ECCS) pump suction strainers and the reactor core isolation cooling (RCIC) pump suction strainer. The submerged portion of the safety relief valve (SRV) and vacuum relief piping is also included, as is the low carbon steel, Non-Class 1 piping.

Detailed visual inspections for evidence of microbiologically influenced corrosion (MIC), pitting or crevice corrosion, or similar mechanisms will be performed on the in-scope components. Plant procedures or directives will be developed to require that in-scope components be examined. These documents will contain specific inspection criteria and will require recording inspection results. A requirement will be included to ensure that information will be reviewed, evaluated and trended.

A.3.7.2 Sample Size and Frequency

The Torus Submerged Components Inspection Program will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

Baseline inspections will be integrated into the routine torus entries. Subsequent inspection frequencies will be determined by engineering evaluation of trends in age-related degradation.

A.3.7.3 Industry Codes, Standards and Acceptance Criteria

Visual inspection will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210, or other suitable method as dictated by the component configuration. Specific inspection techniques and acceptance criteria will be contained in the inspection procedure(s).

A.3.7.4 Aging Effects Requiring an Aging Management Program

Loss of material and cracking are the aging effects that will be monitored by the Torus Submerged Components Inspection Program.

A.4 TIME LIMITED AGING ANALYSES CREDITED FOR LICENSE RENEWAL

A.4.1 TIME LIMITED AGING ANALYSES

The Rule requires that time limited aging analyses (TLAA) be evaluated to capture certain plant-specific aging analyses explicitly based on the original 40 year operating life of the plant. In addition, the Rule requires that any exemptions based on TLAAs be identified and analyzed to justify extension of those exemptions through the renewal term. Plant Hatch did not have any exemptions based on TLAAs.

TLAA evaluations for Plant Hatch included those calculations and analyses that met all six criteria of the Rule, specifically, those calculations or analyses that:

- involved systems, structures and components (SSC) within the scope of license renewal;
- considered the effects of aging;
- involved time-limited assumptions defined by the licensed operating term at the time of the license renewal application;
- were determined to be relevant in making a safety determination;
- involved conclusions or provide the bases for conclusions related to the capability of the SSC to perform its intended functions, as delineated by the Rule; and
- were contained or incorporated by reference in the licensing basis at the time of application for renewal.

Given those six criteria, many calculations and analyses qualified as TLAAs. Those TLAAs were comprehensively evaluated, and dispositioned in section 4 of the license renewal application. A summary listing of those calculations and analysis is shown in Table A.4-1.

Once a TLAA has been identified, the Rule requires it be dispositioned by one of the following three specific criteria:

1. the analyses remain valid for the license renewal term; or
2. the analyses have been acceptably projected to the end of the renewal term; or
3. programs are in place to manage the effect of aging in the analyzed systems, structures or components.

With the exceptions of two areas further discussed below, all of the items in Table A.4-1 were entirely dispositioned by Criterion 1 and/or 2 above. As such, these TLAAs were entirely dispositioned through an update of the existing calculations. The two areas dispositioned in part by Criterion 3 are further discussed below.

A.4.1.1 Stress Analysis Calculations

The stress analysis calculations for the RPV, Class 1 piping, and the torus will be monitored to assure that the cumulative usage factor stays less than or equal to 1.0. The details of this program are further described in sections 4.2 and 5.2 of the Unit 1 and 2 Final Safety Analysis Reports, respectively.

A.4.1.2 Equipment Qualification Report Evaluations

Aging of electrical equipment falling within the scope of 10 CFR 50.49, that has less than a 60-year qualified life, will be managed by the Plant Hatch Environmental Qualification (EQ) Program. The EQ Program is described in section 7.16 and section 3.11 of the Unit 1 and 2 Final Safety Analysis Reports, respectively.

Table A.4-1 Summary Listing of Calculations and Analyses Meeting the Six Time Limited Aging Analyses Criteria

1.	Piping stress analyses that consider thermal fatigue cycles defined by the life of the plant.
2.	Fatigue/stress analyses for the torus structure and nozzle connections.
3.	Piping wall thickness calculations that develop acceptable as-measured criteria for pipe walls based upon an anticipated corrosion rate that, in turn, is based upon the life of the plant.
4.	Calculation of the corrosion allowance assumed for the reactor vessel.
5.	Environmental equipment qualification calculations that qualify electrical components for 40 years.
6.	A containment penetration structural analysis that assumes a number of pressurization cycles over the 40-year life of the plant.
7.	Calculation of the reference temperature for nil-ductility for critical core region vessel materials accounting for radiation embrittlement (as required by 10 CFR 50 Appendix G).
8.	Calculation of the end-of-life equivalent Charpy Upper-Shelf Energy margin (as required by 10 CFR 50 Appendix G) due to the extended operating term.
9.	Analyses performed to demonstrate the acceptability of a technical alternative to the ASME code requirement inspection of reactor pressure vessel circumferential welds.
10.	Change in the anticipated operating cycles of the main steam isolation valves (MSIVs) from the number of cycles assumed for 40 years in the Plant Hatch FSAR.

A.5 GENERAL REFERENCES

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2. TR-112214, Electric Power Research Institute (EPRI), “BWR Vessel and Internals Project, Proceedings: BWRVIP Symposium, November 12-13, 1998.”
3. TR-108705, Electric Power Research Institute (EPRI), “BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection.”
4. TR-107396, “EPRI Closed Cooling Water Chemistry Guidelines.”
5. Edwin I. Hatch Nuclear Plan, Units 1 and 2 Final Hazards Analysis and Fire Protection Program.
6. Southern Nuclear Operating Company, Plant Hatch, Unit 1 & 2, Third 10-Year Interval Inservice Inspection Program.
7. BAW-2270, “Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools,” December 1997.
8. Safety Evaluation enclosed with letter from the Nuclear Regulatory Commission to Southern Nuclear, “Issuance of Amendments – Edwin I. Hatch Nuclear Plant Units 1 and 2,” October 22, 1998.
9. “Development of Class 1 Piping Fatigue Formulas and Fatigue Usage Estimates for the Hatch Nuclear Power Plant, Units 1 and 2,” Report No. SIR-99-078, August 1999.
10. Hatch Units 1 and 2 Torus Fatigue Analysis Report, REA HT-98674 Response, performed by Southern Company Services on April 16, 1999.
11. Electric Power Research Institute, "Recommendations for an Effective Flow-Accelerated Corrosion Program," EPRI NSAC/202-L.
12. Southern Company Services, “Flow-Accelerated Corrosion (FAC) Program, Hatch Nuclear Plant Units 1 and 2,” Volumes 1 and 2.
13. NRC Generic Letter 89-13, “Service Water System Problems Affecting Safety Related Equipment,” July 18, 1989.
14. HL-882, “Georgia Power Company Response to Generic Letter 89-13,” January 23, 1990.
15. Edwin I. Hatch Nuclear Plant Units 1 and 2, Generic Letter 89-13, “Initial Actions Summary Report,” May 1992.
16. NUREG-1275, Volume 3, "Operating Experience Feedback Report - Service Water System Failure and Degradations."
17. A-44985, “Structural Monitoring Program for the Maintenance Rule, Edwin I. Hatch Nuclear Plant,” Units 1 and 2, Revision 4.
18. 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”
19. Contract Report SAND 93-7070, Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers, June 1994.

20. (BWRVIP-01), "BWR Core Shroud Inspection and Flaw Evaluation Guideline, Revision 2, October 1996."
21. (BWRVIP-07), "Guidelines for Reinspection of BWR Core Shrouds February 1996."
22. (BWRVIP-63), "BWR Vessel and Internals Project Shroud Vertical Weld Inspection and Evaluation Guidelines June 1999."
23. (BWRVIP-38), "BWR Shroud Support Inspection and Flaw Evaluation Guidelines September 1997."
24. (BWRVIP-18), "BWR Core Spray Internals and Flaw Evaluation Guidelines July 1996."
25. (BWRVIP-26), "BWR Top Guide Inspection and Flaw Evaluation Guidelines December 1996."
26. (BWRVIP-41), "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines October 1997."
27. (BWRVIP-47), "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines December 1997."
28. (BWRVIP-03), "BWR Reactor Pressure Vessel and Internals Examination Guidelines."
29. ASME Code, Section XI.
30. (BWRVIP-48), "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines EPRI TR-108724, February 1998."
31. ANSI N5.122-1972, Protective Coatings (Paints) for the Nuclear Industry.
32. ANSI N101.2-1972, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities.
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Appendix C

IDENTIFICATION OF AGING EFFECTS AND AGING MANAGEMENT REVIEW SUMMARIES

CONTENTS

C.1 EVALUATION OF AGING EFFECTS REQUIRING MANAGEMENT

Introduction

Section C.1 describes the Plant Hatch approach toward identifying, categorizing and evaluating plant environments, materials and the resulting aging effects applicable to systems, structures, and components at Plant Hatch determined to require aging management reviews. Aging effects determined to be not applicable for a given environment are not discussed.

Plant Hatch has adopted a commodities approach to evaluating aging effects requiring management and aging management programs. Section 3.0 of the LRA provides a discussion of the process utilized to develop commodity groups. Once systems, structures, and components were divided into commodity groups, an analysis of the aging effects requiring management was performed.

Mechanical and electrical discipline evaluations in Appendix C are performed based on the operating environment. Materials of construction, aging effects requiring management, and associated aging mechanisms are appropriately discussed under each environment heading. This section is designed as a reference to be used when reviewing the aging management review summaries located in section 2 of Appendix C. As such, redundancy is incorporated into this section of the document since aging mechanisms may be similar for several different environments.

Civil discipline evaluations are based on material of construction. Environments, aging effects requiring management, and associated aging mechanisms are appropriately discussed under each material of construction heading.

The following definitions are used in this application:

An **aging effect** may be defined as a change in a system, structure, or component's performance, or change in physical or chemical properties resulting in whole or part from one or more aging mechanisms. Examples include loss of material, cracking, loss of fracture toughness, loss of preload, loss of heat exchanger performance, loss of adhesion, and change in material properties.

An **aging mechanism** is any aging process that may result in one or more aging effects.

Change in Insulation Resistance – A change in an insulator's physical or chemical properties such that the required resistance to current or heat flow is no longer provided. A change in insulation resistance may occur due to thermoxidative degradation, water treeing, and radiolysis.

Change in Material Properties – Any change in a material which is detrimental to that material's ability to meet it's design requirements. Mechanisms that may result in a change in material properties include galvanic corrosion, photolysis, radiolysis, thermal degradation, and thermoxidative degradation.

Cracking – Service induced cracking of materials includes both flaw initiation and growth within concrete, concrete masonry, base metals and associated weld materials, and nonmetallics. Aging mechanisms that may result in crack initiation and growth include fatigue, intergranular attack, photolysis and radiolysis of organics, stress corrosion cracking, thermoxidative degradation, and thermal degradation.

Flow Blockage – A reduction in pipeline cross-sectional area such that a significant reduction in flow occurs when the system is called upon to perform its intended function. Flow blockage may be caused by corrosion product buildup, biofouling, particulate fouling, and precipitation fouling.

Loss of Adhesion – A loss of the bond between a structural sealant and the surface to which it is mated. The intrusion of moisture between the sealant and it's mating surface causes a loss of adhesion.

Loss of Conductivity – A loss of the ability of a conductor to carry rated current. Aging mechanisms which cause loss of electrical conductivity include galvanic corrosion and atmospheric corrosion of metals used in terminations and connections.

Loss of Fracture Toughness – A change in the material properties of a metal such that design requirements are potentially compromised. Aging mechanisms that contribute to loss of fracture toughness include irradiation embrittlement and thermal embrittlement.

Loss of Heat Exchanger Performance – A loss of heat exchanger performance due to a buildup of materials on the system surfaces. Loss of heat exchanger performance may occur by any of the mechanisms determined to cause flow blockage.

Loss of Material – A reduction in the material content of a component or structure and may occur evenly over the entire component surface or be confined to localized areas. Aging mechanisms which may result in loss of material include: corrosion of embedded steel in concrete, crevice corrosion, erosion corrosion, galvanic corrosion, general corrosion, selective leaching, microbiologically influenced corrosion, pitting, thermal degradation, thermoxidative degradation, and wear.

Loss of Preload – A general reduction in the tensile load for a bolted connection. Aging mechanisms contributing to loss of preload in bolted connections include embedment, gasket creep, thermal effects, and self-loosening.

C.1.1 PLANT HATCH SERVICE ENVIRONMENTS

The service environment in which components operate, along with other factors, establishes the aging effects of concern for license renewal. This section identifies the service environments for the areas that contain structures and components subject to an aging management review. The service environments identified in this section are thermal, radiation, and moisture.

Thermal Environments

Thermal data were obtained from HVAC design calculations supplemented by actual temperature measurements, and combined into tables. Table C.1.1-1 presents a summary of the thermal environmental conditions by location, so that the structures and components installed in each location can be analyzed for aging resulting from location-specific, worst-case design environments.

Radiation Environments

Design radiation maximums specific to normal operation were obtained from EQ program data. These values are considered conservative maximums. The actual 40-year dose will be lower, and in some cases, much lower. For areas of the plant not listed in the EQ program data, the 40-year dose (gamma) is negligible. Table C.1.1-1 presents a summary of the radiation environments.

The expected normal dose for 60 years at Plant Hatch can be determined by multiplying the 40-year normal dose by 1.5 (i.e., 60 yr/40 yr).

Moisture

Exterior surfaces of structures and components located in yard areas are subject to moisture from weather conditions such as dew, rain, fog, snow, or sleet. Plant Hatch is located in a rural area and is not near major industrial plants or seawater, so the plant is not exposed to sulfate or chloride attack.

Components such as the Intake Structure and associated piping are exposed to the waters of the Altamaha River. Water quality in the Altamaha River is good. Concentrations of minerals and nutrients are low, with dissolved solids typically less than 150 mg/l.

The quality of the groundwater in the vicinity of Plant Hatch is good. The groundwater pH ranges between 7.4 and 7.9. The chloride concentration ranges between 3.0 and 10.0 ppm, and the sulfate concentration ranges between 0 and 20.0 ppm.

Components located inside structures may have short-term exposure to standing water from spills or normal system leakage. Localized corrosion that occurs as a result of a short-term event is corrected through normal plant maintenance activities. These conditions are considered to be event-driven and are not considered in license renewal aging management reviews.

Table C.1.1-1 Plant Hatch Thermal and Radiation Environments

Structure or Area	Specific Area Description and Comments	Max. Temp. (ºF)	60-yr. Radiation Dose (Rads)
Reactor Building Unit 1	Primary Containment	Location Specific	9.17×10^7
Reactor Building Unit 1	Pipe Penetration Room	120	3.0×10^6
Reactor Building Unit 1	Pipe Chase	120	1.02×10^7
Reactor Building Unit 1	HPCI Pump Room	100	8.84×10^3
Reactor Building Unit 1	RHR Corner Room (SE)	100	8.84×10^3
Reactor Building Unit 1	RHR Corner Room (NE)	100	8.84×10^3
Reactor Building Unit 1	RCIC Corner Room (SW)	100	8.84×10^3
Reactor Building Unit 1	CRD Pump Room (NW)	<100	*
Reactor Building Unit 1	Torus Room	120	5.84×10^4
Reactor Building Unit 1	RWCU HX Room	110	9.0×10^6
Reactor Building Unit 1	El. 130’	100	5.84×10^2
Reactor Building Unit 1	El. 158’	100	5.84×10^2
Reactor Building Unit 1	El. 164’	100	5.84×10^2
Reactor Building Unit 1	El. 185’	100	5.84×10^2
Reactor Building Unit 1	El. 203’	100	5.84×10^2
Turbine Building Unit 1	East Cableway	<100	Not Applicable
Reactor Building Unit 2	Primary Containment	Location Specific	9.17×10^7
Reactor Building Unit 2	Pipe Penetration Room	105	3.0×10^6
Reactor Building Unit 2	Pipe Chase	105	1.09×10^7
Reactor Building Unit 2	HPCI Pump Room	105	8.84×10^3
Reactor Building Unit 2	RHR Corner Room (SE)	104	8.84×10^3
Reactor Building Unit 2	RHR Corner Room (NE)	104	8.84×10^3
Reactor Building Unit 2	RCIC Corner Room (NW)	105	8.84×10^3
Reactor Building Unit 2	CRD Pump Room (SW)	105	8.84×10^3
Reactor Building Unit 2	Torus Room	105	5.84×10^4
Reactor Building Unit 2	RWCU HX Room	90	9.0×10^6
Reactor Building Unit 2	El. 130’	90	5.84×10^2
Reactor Building Unit 2	El. 158’	90	5.84×10^2
Reactor Building Unit 2	El. 164’	90	5.84×10^2
Reactor Building Unit 2	El. 203’	90	5.84×10^2
Turbine Building Unit 2	East Cableway	<100	Not Applicable

* No calculated dose for this area. Expected to be similar to Unit 2 CRD Room

Table C.1.1-1 Plant Hatch Thermal and Radiation Environments (Continued)

Structure or Area	Specific Area Description and Comments	Max. Temp. (ºF)	60-yr. Radiation Dose (Rads)
Control Building	Working Floor	<100	Not Applicable
Control Building	Cable Spreading Room	<100	Not Applicable
Control Building	Switchgear Rooms	<105	Not Applicable
Diesel Generator Building		<100	Not Applicable
Intake Structure		<120	Not Applicable

C.1.2 MECHANICAL DISCIPLINE AGING EFFECTS

For each applicable environment identified by mechanical discipline screening, aging effects requiring management and a discussion of the associated aging mechanisms are provided below.

C.1.2.1 Reactor Grade Water

Reactor grade water is used in the power cycle. The water is demineralized and maintained with low levels of detrimental impurities (such as halogens and sulfates) and minimal dissolved oxygen concentrations. This water is supplied to the reactor pressure vessel (RPV) via the condensate and feedwater systems. Reactor water exits the reactor pressure vessel as saturated steam and in some cases two phase flow may exist. Any vapor or two phase environment is considered to be part of the reactor water environment and all aging effects within inscope steam system environments determined to require management are evaluated within the reactor water section. Reactor grade water quality is maintained in accordance with the Reactor Water Chemistry Control Program. This program implements the guidance of EPRI BWR water chemistry guidelines.

The materials of construction exposed to this environment include wrought and forged stainless steel, cast austenitic stainless steel, nickel base alloys, and carbon steel. The aging effects requiring management and associated aging mechanisms applicable to these materials in the reactor water environment are discussed below.

C.1.2.1.1 Loss of Material Within the Reactor Grade Water Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the BWR is a potentially significant aging mechanism for carbon steel within the primary water environment. As will be discussed with flow accelerated corrosion (FAC), low dissolved oxygen contents, (e.g., <30 ppb), achieved to prevent stress corrosion cracking of stainless steels and nickel-base alloys can cause accelerated corrosion of carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic or lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic or higher corrosion potential) decreases. This phenomenon is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. In the reactor water environment carbon steel components electrically coupled to stainless steel or nickel base alloys are susceptible to galvanic corrosion.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant (dissolved oxygen in the BWR coolant) can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, some of which (sulfate and chloride) can accelerate both corrosion and stress corrosion cracking (SCC) initiation and growth. Crevice corrosion is potentially significant for all BWR structural alloys exposed to stagnant environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all BWR structural alloys exposed to stagnant environments.

Microbiologically influenced corrosion (MIC) is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of “living crevices.” This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the reactor water environment, MIC is most likely in stagnant areas having lower operating temperatures.

Wear and fretting are defined as the removal of surface material due to relative motion between surfaces or under the influence of hard, abrasive particles. Mechanical wear occurs in components that experience considerable motion in clamped joints where relative motion is not intended, but occurs due to a loss of clamping force. It may also occur in components that experience relative motion after being held together under high loads with no motion for a long period of time (such as when a flanged joint or valve bonnet is removed for maintenance). Wear and fretting, as an aging mechanism is potentially significant only for large bore Class 1 components where high loads and extreme temperature cycles are involved.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel components within the reactor water environment. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. Erosion corrosion normally occurs when the solution velocity exceeds a threshold value.

Recently, FAC has been used to specifically describe the thinning of carbon steel alloys in nuclear (and fossil) power plants where there is no threshold solution velocity. FAC is a complex phenomenon that is a function of many parameters of water chemistry (pH, oxygen and temperature), material composition, (Cr, Cu and Mo content) and hydrodynamics (steam quality, velocity and geometry) and involves the electrochemical aspects of general corrosion plus the effects of mass transfer and momentum transfer. The correct interpretation of any FAC data depends on evaluation of all of these variables. An indication of how these variables impact carbon steel FAC are listed below:

Variable	**FAC increases if Variable is**
Pipeline Velocity	Higher
pH	Lower
Oxygen	Lower
Steam Quality	0.1 – 0.9
Temperature	250 – 400 °F
Geometry	Conducive to higher turbulence
Chromium content	Lower
Copper content	Lower
Molybdenum content	Lower

FAC can be quantitatively evaluated by utilizing EPRI recommendations for an effective flow accelerated corrosion program. Since stainless steels and low alloy steels have sufficient alloying elements to mitigate FAC, FAC is not an aging phenomenon for these groups of alloys.

Cavitation erosion refers to conditions within a component where, owing to a local pressure drop, cavities filled with vapor are formed; these cavities collapse as soon as the vapor bubbles reach regions of higher pressure. Removal of protective corrosion films and base metal occurs as a result of high localized stresses produced in the metal surface due to collapse of vapor bubbles.

Impingement is characterized by inertial damage of protective corrosion films exposing small anodic regions and has been observed on numerous components exposed to high velocity low quality steam.

C.1.2.1.2 Cracking Within the Reactor Grade Water Environment

Stress corrosion cracking is the term given to this sub-critical crack growth of susceptible alloys under the influence of a tensile stress of sufficient magnitude and a “corrosive” environment. Many alloys when subjected to an external or residual tensile stress and in contact with certain specific environments develop cracks. SCC is a very complex phenomenon that has interrelated mechanical, electrochemical and metallurgical factors.

SCC can proceed through a material in two modes, intergranular (through the grain boundaries) and transgranular (through the grains). Sometimes the modes are mixed or the mode switches from one mode to the other. Intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC) often occur in the same alloy depending on the environment, the microstructure or the stress/strain state. IGSCC is the predominate form of SCC in the BWR.

For the BWR, the initiation of IGSCC of structural materials in the reactor water environment occurs when the following necessary conditions are simultaneously present:

Susceptible material – The IGSCC of stainless steel and nickel base alloys predominately requires a chromium depleted zone at the grain boundary in weld heat affected zones (HAZs) due to chromium carbide ($Cr_{23}C_6$) precipitation, i.e., “sensitization.” However, sensitization is not necessary if the material is creviced or cold worked. IGSCC susceptible structural materials include essentially all austenitic stainless steels, (e.g., Types 304, 316, 304L, 316L, etc.), nickel-base alloys, (e.g., Alloy 600, X-750, etc.), and nickel-base weld metals, (e.g., Alloy 182, 82, etc.). Austenitic stainless steel weld metal is highly resistant to IGSCC.

Tensile stress - The threshold tensile stress for IGSCC typically exceeds the material's at-temperature yield stress. Sources of tensile stress include applied, residual, thermal, welding and even corrosion product. As-welded material typically contains weld residual tensile stresses approaching the yield stress of the material. The threshold tensile stress for IGSCC is reduced by 50% if the material is creviced.

Corrosive environment – High temperature water where the electrochemical corrosion potential (ECP) of alloys within the coolant is increased due to the presence of radiolytically produced dissolved oxygen and hydrogen peroxide is necessary for IGSCC initiation. Although the presence of detrimental impurities such as sulfate and chloride are not required for IGSCC in the BWR, their presence at levels as low as 5 ppb will accelerate both IGSCC initiation and crack propagation.

A reduction in the susceptibility of alloys to IGSCC in the BWR has been accomplished through the use of sensitization resistant materials such as Type 316NG stainless steel (Hatch Unit 2 recirculation piping), solution heat treatment, corrosion resistant cladding and weld overlays. Tensile stress reduction techniques include heat sink welding, induction heating stress improvement, and mechanical stress improvement.

Irradiation assisted stress corrosion cracking (IASCC) is also a form of IGSCC. However, there are some major differences between the two phenomena that warrant their different designations. First, stainless steel that suffers IASCC is not thermally "sensitized." Second, the IASCC phenomenon is material irradiation exposure time dependent, i.e., unlike sensitized stainless steel where the material is susceptible to IGSCC from day one, annealed stainless steel only becomes susceptible upon exceeding a certain threshold fluence value as a function of stress level.

As modeled on IGSCC, the initiation of IASCC in austenitic stainless steel reactor internals appears to occur when the following necessary conditions are simultaneously present:

Susceptible material – Radiation induced segregation of impurities, (e.g., P, Si, S), nickel enrichment and mild chromium depletion at the grain boundary in annealed material, i.e., classical thermal sensitization not required, as a result of a fluence exceeding ~3-5 x 10^{20} n/cm^2 E>1.0 MeV. The primary physical effect of irradiating a metal with fast neutrons is the displacement of atoms, the subsequent production of vacant lattice sites (vacancies) and interstitials and enhanced diffusion.

Tensile stress – Unlike the IGSCC for uncreviced BWR piping, the threshold stress level for IASCC is below the yield stress, time dependent and is a function of fluence. Also, irradiation can lead to stress relaxation via a creep mechanism or to a stress increase through the formation of hydrogen atoms by radiolysis and transmutation. Also, because of the highly oxidizing nature of the environment, corrosion oxide films tend to be much thicker than for IGSCC. Since the oxide on stainless steel has a greater specific volume than the parent corroded metal, IASCC crack growth can also be driven by the resultant oxide wedging stresses that result from thick oxide at the crack tip.

Corrosive environment – High temperature water where the electrochemical corrosion potential (ECP) of the stainless steel in the coolant is increased due to the presence of radiolytically produced dissolved oxygen and hydrogen peroxide. Although the presence of detrimental impurities such as sulfate and chloride are not necessary for IASCC in the BWR, their presence will accelerate both IASCC initiation and crack propagation.

At Plant Hatch, only a small set of near core internals exceed the neutron fluence threshold required to render a component susceptible to IASCC.

Intergranular attack (IGA) is the precursor of IGSCC in the reactor water environment. Since grain boundary atoms even in “pure” metals are more loosely packed than the matrix material, grain boundaries preferentially corrode. This is normal for general corrosion where the grain boundary corrodes at only a slightly higher rate than the grain. However, alloys such as stainless steels and nickel-base alloys are more readily attacked due to impurity segregation, (e.g., P, Si, S, etc.), enrichment or depletion of alloy elements, (e.g., sensitization), and/or heat treatment induced solid state reactions. When the grain boundaries are affected by one or more of these three factors, the degree of localized attack is significantly more severe. Once the depth of IGA exceeds 2 mils, it electrochemically acts as a crack. The presence of a tensile stress greater than the threshold stress will subsequently result in IGSCC propagation. Aside from initiating IGSCC, IGA serves as nucleation sites for pitting and environmentally assisted fatigue.

Thermal fatigue is a structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. The reactor recirculation pump covers and integral heat exchangers have been proven especially susceptible to cracking due to thermal fatigue cycles. Carbon steels, alloy steels, austenitic stainless steels, and nickel base alloys are all susceptible to damage due to fatigue resulting from thermal cycling. The presence of an oxidizing environment, as the Hatch primary coolant pressure boundary piping system was exposed to prior to implementation of hydrogen water chemistry, can accelerate the fatigue crack initiation and propagation process. This is commonly referred to as environmentally assisted fatigue or corrosion fatigue. Based on the decision criteria and conservative formulae utilized in creating cumulative usage factor equations for Class 1 components, environmental effects of reactor water have been adequately incorporated into the Plant Hatch Component Cyclic or Transient Limit Program. Therefore, the thermal fatigue aging mechanism identified throughout ASME Class 1 sections of this application is also considered to encompass any relevant environmental effects of reactor water.

C.1.2.1.3 Loss of Fracture Toughness Within the Reactor Grade Water Environment

Thermal embrittlement of cast austenitic stainless steels may occur based on prolonged exposure to operating temperatures in excess of 480 °F. The resulting aging effect is a reduction in the fracture toughness of a material as a function of time. The magnitude of the reduction depends on casting method, material chemistry, and the duration of exposure to operating temperatures conducive to the embrittlement process. Based on the EPRI screening guidelines for evaluation of thermal embrittlement for cast austenitic stainless steels, a limited subset of castings at Plant Hatch have been determined to be potentially susceptible to thermal embrittlement. These castings include reactor recirculation pump casings and covers, and certain large bore valve bodies within the reactor recirculation system.

Irradiation embrittlement (neutron embrittlement) is the result of atomic displacements within a material due to atomic collisions. These displacements produce defects that change the property of the metal and result in a loss of fracture toughness. Irradiation embrittlement is a function of two variables:

- Copper and nickel content within the alloy.
- Neutron fluence exceeding a minimum threshold value.

Only RPV alloy steel beltline shells and associated welds and certain austenitic stainless steel RPV internals exposed to neutron fluences exceeding the minimum threshold value are potentially susceptible to loss of fracture toughness due to irradiation embrittlement.

C.1.2.2 Auxiliary Systems (Demineralized, Suppression Pool, Spent Fuel Pool, and Borated Waters)

Auxiliary system environments are those with the potential to cross tie to the reactor pressure vessel. The water in these systems is demineralized (pure) with no corrosion inhibiting chemical or biocide additions and no control of dissolved oxygen concentrations. While acceptable levels for impurities may vary among systems, these differences are driven by the relative potential for any given system to supply water to the reactor pressure vessel and not focused on excluding aging effects. The aging effects requiring management and definitions of associated aging mechanisms are similar for all auxiliary systems. Chemistry parameters for these systems implement the recommendations of EPRI BWR water chemistry guidelines. At Plant Hatch, four “auxiliary systems environmnets” are included within this evaluation:

Demineralized Water is processed by an on site demineralizing system and is stored in the demineralized water storage tanks and condensate storage tanks. Detrimental impurities and conductivity are maintained at low levels but dissolved oxygen concentrations are not controlled or monitored.

Suppression Pool Water (Torus Water) is contained within the torus and consists of demineralized water supplied from demineralized water sources (such as the condensate storage tanks). Detrimental impurities and conductivity are maintained at low levels, though allowable levels are well above those acceptable for demineralized water. Dissolved oxygen concentrations are not controlled or monitored.

Spent Fuel Pool Water is contained within the spent fuel pool and consists of demineralized water supplied from demineralized water sources (such as the demineralized water storage tank). Detrimental impurities and conductivity are maintained at low levels similar to the levels maintained within the suppression pool water environment. Dissolved oxygen concentrations are not controlled or monitored.

Borated Water is contained within the standby liquid control system and consists of demineralized water supplied from the demineralized water storage tank, with approximately 10% by weight sodium pentaborate added. Sodium pentaborate solutions have pH values in the neutral range. While conductivity within this solution is high, the concentrations of aggressive anion species are quite low, thereby minimizing significant corrosion within the system. The standby liquid control storage tank is not regularly monitored for detrimental impurities.

The materials of construction exposed to these pure water environments include stainless steel, carbon steel, galvanized steel (used in the CST only), and aluminum alloys (used in the CST and spent fuel pool only). The aging effects requiring management and associated aging mechanisms applicable to these materials in these auxiliary system water environments are discussed below.

C.1.2.2.1 Loss of Material Within Auxiliary System Water Environments

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in auxiliary systems is a potentially significant aging mechanism only for carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within auxiliary systems, carbon steel and aluminum alloys may be susceptible to galvanic corrosion when electrically coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to stagnant environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to stagnant environments.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of “living crevices.” This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth.

Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In auxiliary system environments, MIC is most likely in stagnant areas having lower operating temperatures.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel components within auxiliary systems. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. Erosion corrosion normally occurs when the solution velocity exceeds a threshold value and is potentially significant within auxiliary systems in areas of high turbulence or pressure fluctuations.

Cavitation erosion refers to conditions within a component where, owing to a local pressure drop, cavities filled with vapor are formed; these cavities collapse as soon as the vapor bubbles reach regions of higher pressure. Removal of protective corrosion films and base metal occurs as a result of high localized stresses produced in the metal surface due to collapse of vapor bubbles. Cavitation erosion may be possible within auxiliary systems in areas of substantial localized pressure changes such as downstream of reduction orifices or throttle valves.

C.1.2.2.2 Cracking Within Auxiliary Systems Water Environments

Stress corrosion cracking occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. For a particular material, high stresses require less corrosive environments, and highly corrosive environments require less stress to initiate and propagate cracking. Elimination or reduction in any of these three factors will decrease the likelihood of SCC occurring. SCC can be categorized as either IGSCC or TGSCC, depending upon the primary crack morphology. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and environment. Within the auxiliary systems environments a low temperature threshold temperature of 140 °F was assumed for stress corrosion cracking of stainless steel. Based on this threshold, only certain stainless steel components in the HPCI and RCIC turbine discharge headers inside the torus, where operating temperatures occasionally exceed 200 °F, are postulated to be susceptible to SCC.

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though auxiliary system water temperatures are generally less than 120 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.3 Closed Cooling Water

Closed Cooling Water is monitored for detrimental impurities, though the parameters are less restrictive than for reactor water or auxiliary system water environments. Corrosion inhibitors designed to form passivating films on anodic surfaces are utilized. A basic pH is maintained to increase the effectiveness of the corrosion inhibitors and promote the development of protective corrosion films. Biocide levels are maintained to prevent significant microorganism growth. Guidelines for acceptable chemistry parameters for closed cooling water systems are in accordance with EPRI closed cooling water chemistry guidelines.

The materials of construction exposed to these closed cooling water environments include stainless steel, carbon steel, and brass. The aging effects requiring management and associated aging mechanisms applicable to these materials in closed cooling water environment are discussed below.

C.1.2.3.1 Loss of Material Within the Closed Cooling Water Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the closed cooling water environment is a potentially significant aging mechanism only for carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within the closed cooling water environment, carbon steels may be susceptible to galvanic corrosion when coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to stagnant environments except for brass components having high zinc content that prevents significant crevice corrosion from occurring.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion (i.e., deaerated, stagnant, low pH and high impurity concentration). While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to stagnant environments except for brass components having high zinc content that prevents significant pitting from occurring.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the closed cooling water environment, MIC is most likely in stagnant areas of the systems.

Selective leaching (also known as dealloying corrosion) of brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the closed cooling water environment.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel components within the closed cooling water environment. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. Erosion corrosion normally occurs when the solution velocity exceeds a threshold value and is potentially significant within the closed cooling water environment in areas of high turbulence or pressure fluctuations.

C.1.2.3.2 Cracking Within the Closed Cooling Water Environment

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though closed cooling water temperatures are less than 120 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAAs and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.4 Raw Water (River Water and Well Water)

Two types of raw water are defined:

River water is supplied from the Altamaha River via the intake structure. Water supplied from the Altamaha River is rough screened at the intake structure. This screening is designed to prevent clogging of vertical turbine pumps and discharge strainers. It is assumed that some debris, silt, and macroorganisms may be introduced into the plant service water and residual heat removal service water systems. The materials of construction exposed to the river water environment include: stainless steels, carbon steel, cast iron, brass, and copper.

Well water is supplied from deep draft wells located on site. Well water is mechanically filtered using the demineralizing system filters prior to use to remove macroorganisms and silt and is utilized by fire protection systems only. Many different material types are exposed to the well water environment.

C.1.2.4.1 Loss of Material within the Raw Water Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the raw water environment is a potentially significant aging mechanism for carbon steels and cast irons.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within the river water and well water environments, carbon steels and cast irons, and copper alloys, to a lesser degree, may be susceptible to galvanic corrosion when electrically coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to stagnant environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to stagnant environments.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the raw water environment, MIC is most likely in stagnant areas with heavy corrosion product buildup.

Selective leaching (also know as dealloying corrosion) of cast iron and brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the raw water environment.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel and cast iron components within the river water environment. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. Erosion corrosion normally occurs when the solution velocity exceeds a threshold value and is potentially significant for carbon steel and cast iron within the raw water environment in areas of high turbulence or pressure fluctuations.

Fouling may be due to particulate, precipitation, or biological organisms. As with MIC, fouling is not a material degradation phenomenon but may increase corrosion rates within raw water system components for a limited set of component geometries. In these areas, particulate, precipitates, or biological organisms adhere to the component surface and create shielded areas and crevices that promote localized corrosion mechanisms. Fouling mechanisms are described in greater detail in section C.1.2.4.3.

Wear is an applicable aging mechanism requiring management for tube to tubesheet and tube to baffle connections within the RHR heat exchangers. Vibration within the heat exchanger can cause collisions of tubes and baffles to occur, thereby resulting in loss of material within the heat exchangers.

C.1.2.4.2 Cracking within the Raw Water Environment

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though raw water temperatures are less than 120 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

Vibration fatigue is an applicable aging mechanism for the RHR heat exchangers. Cyclic loads are experienced at all times during heat exchanger operations and industry experience indicates damage due to vibration within these heat exchangers has occurred. The tubes and tubesheets are most susceptible to vibration fatigue.

C.1.2.4.3 Flow Blockage Within the Raw Water Environment

Fouling may result in a significant buildup of material on raw water system component internal surfaces. This buildup will most likely occur in areas having creviced geometries and lower pipeline velocities. Eventually the reduction of flow area will result in an inability of the system to meet its intended function since sufficient flow and adequate pressure may not be delivered. As described above, fouling may also create areas conducive to localized corrosion mechanisms. The following four types of fouling are considered significant within raw water systems at Plant Hatch:

- **Corrosion product buildup** may be expected to occur in all river water and well water components since no chemistry controls are employed to limit general corrosion rates in carbon steels and cast irons. Corrosion products may be transported throughout the system and deposited on materials not generally considered susceptible to general corrosion. Heavy corrosion product buildup on component surfaces produces shielded areas along the material surface where crevice corrosion, pitting, and MIC may be promoted. Heavy corrosion product buildup on component surfaces can also lead to a reduction of flow area.
- **Biofouling** may occur via microbiological organisms or macroorganisms. Any biological organisms introduced into raw water systems may deposit on component surfaces and create biofilms that are conducive to localized corrosion mechanisms and provide ideal locations for further buildup of material on component surfaces. Fouling due to macroorganisms is only significant in river water systems (service water). Fire protection systems are supplied by onsite wells with filtering employed to eliminate the possibility of macroorganisms entering the system.
- **Particulate fouling** consists of both river silt and other larger debris fine enough to pass through the intake pit screens and enter the service water systems. Particulate fouling is not considered plausible for fire protection systems since filters would eliminate intrusion of particulates into the system.
- **Precipitation fouling** may occur when mineral compounds are precipitated out of solution and adhere to component surfaces. Precipitation fouling is most prevalent within heat exchanger surfaces.

C.1.2.4.4 Loss of Heat Exchanger Performance Within the Raw Water Environment

Loss of heat exchanger performance is restricted to the RHR system heat exchangers. See section C.2.2.11.1.

Fouling - All of the fouling types described in section C.1.2.4.3 are applicable to RHR heat exchangers. Any buildup of material on heat exchange surfaces will result in some loss of heat exchanger performance.

C.1.2.5 Fuel Oil

Fuel oil is any oil utilized to fuel an internal combustion engine. The materials of construction for this internal environment include stainless steel, carbon steel, brass, bronze, copper, and gray cast iron. The aging effects requiring management and associated aging mechanisms applicable to these materials in the fuel oil environment are discussed below.

C.1.2.5.1 Loss of Material Within the Fuel Oil Environment

Fuel oils in their pure form are nonaggressive and noncorrosive to metals. However, intrusion of water contamination will create an aggressive environment within fuel oil system components and additives to fuel oils may increase the potential for corrosion if water intrusion occurs. Loss of material due to corrosion may only occur if water contamination is present. If the assumption is made that water intrusion from rain or ground water is possible, a conservative estimate of the potential aging mechanisms is obtained. The reader is referred to the raw water section (C.1.2.4) of this document for a description of how these aging mechanisms apply and proceed in various materials. No discussion of specific aging mechanisms leading to loss of material is provided in this section.

C.1.2.5.2 Cracking Within the Fuel Oil Environment

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.5.3 Flow Blockage

Flow blockage due to buildup of sediment has been determined to be applicable for copper tubing supply lines to the fire protection pump diesel engine.

C.1.2.6 Gases

The gas environment is defined as any line containing noncondensable gases and includes both dried and nondried gases.

Dried gases describe any process gas including, but not limited to, air, nitrogen (including cryogenic), carbon dioxide, hydrogen, helium, and fluorocarbons supplied from a tank or bottle or is filtered and desiccated to remove moisture prior to entering the system. Sufficient moisture to drive aging mechanisms is not present. The only aging effect requiring management for dried gases is cracking due to thermal fatigue. This is a conservative assumption and thermal fatigue is managed by TLAA. See section 4.2.3 of the LRA.

Nondried gases include air (nitrogen in the case of the inerted drywell) containing humidity or significant moisture. Nondried gas environments are found inside buildings, inside the drywell, and outside. These gases are assumed to contain sufficient entrained moisture and oxygen to enable pooling of liquid at low or especially cool locations and promote corrosion. Containment atmosphere processed by inscope systems is considered within this category of internal environment.

The materials of construction exposed to a gas environment include carbon steel, stainless steel, galvanized steel, and copper alloys.

C.1.2.6.1 Loss of Material Within the Gas Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the nondried gas environment is a potentially significant aging mechanism for carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within a nondried gas environment, carbon steels may be susceptible to galvanic corrosion when electrically coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to pooling or wet/dry nondried gas environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to pooling or wet/dry nondried gas environments.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of “living crevices.” This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the nondried gas environment, MIC is only potentially significant in areas where long term pooling of liquid occurs.

Selective leaching (also known as dealloying corrosion) of cast iron and brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the nondried gas environment wherever significant pooling may occur on brass or cast iron surfaces.

C.1.2.6.2 Cracking Within the Nondried Gas Environment

Stress corrosion cracking occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. For a particular material, high stresses require less corrosive environments, and highly corrosive environments require less stress to initiate and propagate cracking. Elimination or reduction in any of these three factors will decrease the likelihood of SCC occurring. SCC can be categorized as either IGSCC or TGSCC, depending upon the primary crack morphology. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and environment. Within the nondried gas environment certain stainless steel components are located in areas where pooling of moisture and wet/dry cycling are possible. In addition, the location of these components (upper elevations of the drywell or near main steam lines) are such that ambient temperatures approach 200 °F at times. Plant Hatch has assumed a 140 °F threshold temperature for initiation of SCC. Based on this environment, SCC is a potentially significant aging mechanism for certain stainless steel components.

Intergranular attack initiates by a mechanism similar to stress corrosion cracking and has been also assumed to have a lower threshold temperature of 140 °F below which IGA will not occur. Therefore, as with SCC, only those stainless steel, nondried gas system components exposed to upper drywell atmosphere or near main steam components are susceptible to IGA.

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though gas system temperatures are generally less than 200 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.7 Pressure Boundary Bolting

Pressure boundary bolting includes carbon steel, alloy steel, and stainless steel bolting, applicable to license renewal. The following aging effects and mechanisms are applicable to Class 1 and non-Class 1 bolting. Note that cracking due to thermal fatigue is applicable only to reactor pressure vessel closure head studs due to high installation tensile stresses and extreme thermal cycles.

C.1.2.7.1 Loss of Material

Loss of material may occur within fasteners by several different corrosion mechanisms. Fasteners experience environments similar to any other mechanical component external surface—inside, outside, and buried—with an increased potential for wetting than other piping components due to gasket leakage. At Plant Hatch, buried fasteners only exist in a few areas within fire protection systems. Since the environments are similar, although the many shielded areas and crevices associated with threaded connections increase the potential for significant corrosion, loss of material mechanisms for fasteners are included with mechanical external surfaces aging mechanism descriptions.

C.1.2.7.2 Loss of Preload

Embedment - Fastener and joint surfaces are microscopically rough. When first assembled, these surfaces only contact each other on high spots. These high spots tend to creep and flow until a larger surface contact area is obtained. Preload is lost as these parts "settle in" together. Joints subject to large cyclic loads will embed and relax more than joints under static loads. Therefore, embedment is a significant aging mechanism for all pressure boundary bolting, regardless of material of construction.

Gasket creep - To function properly, gaskets are designed to deform plastically when loaded. Minor loss of preload may be experienced as these gaskets "creep," that is, to gradually flow or compress outward under a compressive load. Therefore, gasket creep is a significant aging mechanism for all pressure boundary bolting, regardless of material of construction.

Thermal effects - Differential expansion between bolts and joint members due to thermal effects may increase stresses and thereby cause embedment or gasket creep. Creep of bolts and gaskets can be promoted by high temperature through a process called stress relaxation. Since significant thermal cycles are required to produce thermal effects, only those fasteners operating at higher temperatures are susceptible to this aging mechanism.

Self-loosening - Vibration, flexing of the joint, cyclic shear loads, thermal cycles, and other factors can cause whole or partial self-loosening of a fastener. Therefore, self-loosening is a significant aging mechanism for all pressure boundary bolting, regardless of material of construction.

C.1.2.7.3 Cracking

Thermal fatigue is a structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. The reactor pressure vessel closure head studs are susceptible to cracking due to thermal fatigue cycles. These fasteners represent a high stress area within the Class 1 boundary. Other bolting at Plant Hatch is not installed with sufficient stresses to cause fatigue to be a significant mechanism.

C.1.2.8 Inside

An inside environment indicates that the equipment is sheltered from the weather. The inside environment assumes 50% - 90% humidity, an ambient temperature less than 120 °F (except for primary containment), and a maximum radiation level of 9.0×10^6 rads. The inside environment also includes components located within the primary containment structure. The containment environment assumes 40% - 90% humidity, a bulk average ambient temperature defined by data obtained from RTDs, and a maximum radiation level of 9.17×10^7 rads outside the sacrificial shield wall.

The materials of construction having an inside environment include carbon steel, stainless steel, galvanized steel, and copper alloys.

C.1.2.8.1 Loss of Material Within the Inside Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. However, significant general corrosion is limited to carbon steel components operating at less than 200 °F since any component with an external surface temperature greater than 200 °F would not retain surface moisture for a significant amount of time and subsequently, corrosion rates will be limited.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Therefore, galvanic corrosion is a potentially significant aging mechanism for carbon steels and cast irons whenever wetted conditions exist and electrical connections to stainless steel components are simultaneously present.

Selective leaching (also know as dealloying corrosion) of cast iron or brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the inside environment anywhere localized wetting is possible.

C.1.2.8.2 Cracking

Thermal fatigue is the structural deterioration of a material that can occur whenever contraction or expansion of a body resulting from a change in temperature is prevented by some constraint. These constraints may either be externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas.

C.1.2.9 Outside

Outside is defined as any external environment found outside any structure that would protect it from the weather. The environment assumes 0% to 100% humidity, an ambient temperature less than 120 °F, and no radiation.

The materials of construction having an outside environment include carbon steel, stainless steel, galvanized steel, cast iron, aluminum alloys, and copper alloys.

C.1.2.9.1 Loss of Material Within the Outside Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. In the outside environment general corrosion is limited to carbon steel and cast iron components and will be most significant in areas where pooling of rainwater or process waters occurs.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Therefore, galvanic corrosion is a potentially significant aging mechanism for carbon steels and cast irons whenever wetted conditions exist and electrical connections to stainless steel components are simultaneously present.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to pooling or wet/dry within the outside environment.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to pooling or wet/dry within the outside environment.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of “living crevices.” This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the outside environment, MIC is only potentially significant in areas where long term pooling of liquid occurs.

Selective leaching (also known as dealloying corrosion) of cast iron or brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism in the outside environment anywhere localized wetting is possible.

C.1.2.9.2 Cracking

Thermal fatigue is the structural deterioration of a material that can occur whenever contraction or expansion of a body resulting from a change in temperature is prevented by some constraint. These constraints may either be externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas.

C.1.2.10 Buried or Embedded

The buried or embedded environment includes components buried beneath the surface of the ground (in some cases with controlled backfills) or embedded in structural concrete.

The materials of construction having a buried or embedded environment include carbon steel, stainless steel, cast iron, and copper.

C.1.2.10.1 Loss of Material Within the Buried or Embedded Environment

Underground carbon steel piping is covered with a protective coating that is expected to greatly reduce the rates of corrosion occurring on the external surfaces of buried piping. Plant Service Water (PSW), Residual Heat Removal Service Water (RHRSW), and Diesel

Fuel Supply Piping were coated with enamel and wrapped with a fiber wrap saturated in coal tar in accordance with AWWA C203-66 when buried. These coatings are expected to prevent corrosion except in those locations where the coating is breached.

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. Wetting due to groundwater is possible for all buried components and therefore general corrosion is a potentially significant aging mechanism for buried carbon steel components.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Therefore, galvanic corrosion is a potentially significant aging mechanism for carbon steels when groundwater wetting of the components and electrical connections to stainless steel components are simultaneously present.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all susceptible structural alloys exposed to groundwater within the buried environment.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all susceptible structural alloys exposed to groundwater within the buried environment.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of “living crevices.” This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the outside environment, MIC is only potentially significant in areas where long term wetting of susceptible surfaces by groundwater occurs.

Selective leaching (also known as dealloying corrosion) of brass components occurs when the more active (anodic) zinc within the matrix is preferentially corroded and the copper portion of the matrix remains. Therefore, selective leaching is a potentially significant aging mechanism within the buried environment.

C.1.2.11 Aging Effects Requiring Management for Insulation Components

C.1.2.11.1 Loss of Material

Intrusion of water and water borne agents applies to insulation located outside and nonembedded fire penetration seal insulating materials. Water may ingress through the protective insulation sheathing and collect in the insulation system. The water may contain agents such as nitrates, sulfates, hydrogen ions, minerals, salts, etc. which can have a deteriorating effect on insulation materials, resulting in loss of material and a subsequent loss of insulation effectiveness.

Wear can occur when there is relative motion or sliding between stationary objects such as pipe supports and walls, and insulation. Insulation material can be rubbed off the pipe, equipment, or penetration seal and reduce its effectiveness. Relative motion can be created by thermal movement, vibration, and dynamic effects such as hydraulic transients. When relative motion occurs, insulating materials may degrade due to wear.

C.1.2.11.2 Cracking

Thermal degradation may be due to elevated temperature degradation or low temperature degradation. Elevated temperature degradation applies to outside insulation used with heat tracing and embedded fire penetration seals. These insulation materials can experience cracking when exposed to high temperatures over a long period of time. Heat aging cracks can reduce insulation effectiveness. Low temperature degradation applies to the diesel CO_2 storage tank insulation only. The refrigeration system for this tank maintains the CO_2 at a constant 0 °F. Insulation materials can experience cracking when exposed to continuously low temperatures over a long period of time. Aging cracks can reduce insulation effectiveness.

Intrusion of water and water borne agents applies to outside insulation and nonembedded fire penetration seal insulating materials. Water may ingress through the protective insulation sheath and collect in the insulation system. Repeated freeze/thaw cycles may cause the insulation material to crack.

C.1.2.11.3 Change in Material Properties

Compaction/settling due to dead weight and/or gravity has been determined to be a significant aging mechanism for insulation. Insulation can experience compaction and/or settling due to its own weight and the weight of protective jackets (outside insulation) or the weight of pipes/conduits (fire penetration seals) over a long period of time. Compaction and/or settling reduces the insulation thickness which can reduce insulation effectiveness.

Compaction/settling due to intrusion of water and water borne agents applies to outside insulation and nonembedded fire penetration seals. Water may ingress through the protective insulation sheath and collect in the insulation system. This may cause the insulation to become soggy resulting in compaction or settling of the insulation material and thus reduce its thickness. Water soaked insulation may also sag and pull away from the piping or equipment being insulated. Reduced thickness or sagging insulation can result in reduced insulation effectiveness.

Thermal degradation may be due to elevated temperature degradation or low temperature degradation. Elevated temperature degradation applies to outside insulation used with heat tracing and embedded fire penetration seals. Insulation material can experience a breakdown in the structural properties which bond adjacent layers of material together when exposed to high temperatures over a long period of time. This heat aging process can result in separation of layers of material for piping and equipment insulation. For fire penetration seals, this heat aging process can result in both separation of layers of material and separation from walls or components. Low temperature degradation applies to the diesel CO_2 storage tank insulation only. The refrigeration system for this tank maintains the CO_2 at a constant 0 °F and the insulation is continuously exposed to this low temperature. Insulation material can experience a breakdown in the structural properties which bond adjacent layers of material together when exposed to low temperatures over a long period of time. This process can result in separation of layers of insulation material. Material separation can reduce insulation effectiveness.

C.1.3 ELECTRICAL AGING EFFECTS

The process to determine aging effects applicable to electrical components begins with an understanding of the aging effects identified in the industry literature. From this set of aging effects, those which require management are determined by examining the component materials, service environments, and operating stresses for each component type. In addition to the review of industry literature, Plant Hatch-specific operating experience was reviewed to provide reasonable assurance that all aging effects were identified for the aging management review.

After defining the various internal and external environments to which a particular component/commodity may be exposed, it is next necessary to discuss the particular aging mechanisms and aging effects that may be present in these environments. Aging effects and aging mechanisms can be defined as follows:

An aging effect may be defined as a change in a system, structure, or component's performance, or change in physical or chemical properties resulting in whole or part from one or more aging mechanisms. Examples for electrical components include change in insulation resistance, change in material properties, cracking, loss of conductivity, and loss of material.

An aging mechanism is any aging process that may result in one or more aging effects. Aging mechanisms for electrical discipline components include: atmospheric oxidation of metals, galvanic corrosion, hydrolytic degradation, photolysis of organic materials, radiolysis of organic materials, thermal degradation of organic materials, thermoxidative degradation, and water treeing.

Electrical component types subject to an aging management review (AMR) are electrical cables, connectors, splices, terminal blocks, Nelson frames, and phase bussing. The identification of the aging effects requiring management for electrical components considered the following list of aging effects, which has been compiled by reviewing available industry literature.

- Loss of Material – Loss of material is a reduction in the material content of a component or structure and may occur evenly over the entire component surface or be confined only to localized areas.
- Cracking – Defects in nonmetallic materials resulting in physical separation, typically beginning at the surface and progressing through the material. Cracking in nonmetallic materials is a primary concern for cable insulation and jacket material.
- Loss of Conductivity – Inability of a component to carry sufficient electrical current.
- Change in Insulation Resistance – A change in an insulator's physical or chemical properties such that the required resistance to current or heat flow is no longer provided.
- Change in Material Properties – Any change in a material which is detrimental to that material's ability to meet its design requirements.

These aging effects can be expected to occur due to the following aging mechanisms depending upon environmental conditions:

- Thermal degradation of organic materials
  - Loss of material
  - Cracking / Embrittlement
  - Change in material properties
  - Change in insulation resistance
- Thermoxidative degradation
  - Loss of material
  - Cracking / Embrittlement
  - Change in material properties
  - Change in insulation resistance
- Radiolysis of organic materials
  - Cracking / Embrittlement
  - Change in insulation resistance
  - Change in material properties
- Water treeing
  - Change in insulation resistance

Three environmental conditions must be evaluated to assess the aging effects associated with nonmetallic materials used in electrical components at Plant Hatch. These are high temperature, radiation, and moisture. A summary of the evaluations of the aging effects associated with these environmental conditions for each electrical component type follows.

High Temperature Aging Effects

High temperatures can result in thermal degradation and thermoxidative degradation of electrical components. The EQ Program has evaluated the effects of high temperatures on electrical components within the scope of the program. Arrhenius methodology is used to analyze thermal test data and calculate qualified lives for the various components in the program. Since electrical cables, connectors, splices, and terminal blocks within the scope of license renewal have already been tested and evaluated for high temperature aging effects by the EQ program, the EQ data and evaluations can be used to determine whether or not aging effects associated with high temperature require management for the components within the scope of license renewal.

Electrical cables, connectors, splices, and terminal blocks within the license renewal scope are located throughout the reactor building, control building, the lower regions of the drywell (primary containment), certain limited areas of the turbine building, and in various other buildings such as the diesel generator building and the intake structure. Allowable temperatures corresponding to a 60-year service life for these component types were compared to the maximum bounding temperatures of the various plant areas. In all cases, the plant temperatures were lower than the allowable 60-year temperatures of the components. From this it is concluded that no aging effects associated with high temperature require management for electrical cables, connectors, terminal blocks, and splices.

The same types of evaluation were performed for Nelson frames and phase bussing. While these component types are not within the scope of the EQ program, the nonmetallic materials associated with these components were evaluated using an industry material database, and 60-year temperatures were determined. These were greater than the applicable plant temperatures in all cases. No aging effects associated with high temperature require management for Nelson frames or phase bussing.

Radiation Aging Effects

A radiation environment can result in radiolysis of organic materials. Aging effects associated with radiation have been evaluated for electrical cables, connectors, splices, and terminal blocks in the EQ Program. Allowable 60-year radiation doses have been determined for these components. Using this data, the allowable 60-year doses for the components within the license renewal scope were determined. These values were compared to the calculated dose associated with each plant area in which the components are located. The allowable dose is greater than the expected dose in all cases. No aging effects associated with radiation require management for cables, connectors, splices, or terminal blocks.

The materials of construction of Nelson frames and the portion of phase bussing in scope have been evaluated for radiation aging effects using industry material data. The allowable dose for these components is greater than the expected dose in all cases. No aging effects associated with radiation require management for Nelson frames and the portion of phase bussing within the license renewal scope.

Aging Effects Related To Moisture

Water penetration into electrical cable insulation can result in reduced dielectric strength due to increased conductivity of the insulation caused by increased ion mobility and concentration. Increased conductivity results in increased leakage current flowing either through or on the surface of the insulation, eventually resulting in permanently degraded dielectric strength. Cables constructed with ethylene propylene rubber insulation have a relatively high resistance to moisture intrusion.

Water treeing is a degradation and long-term failure phenomenon, which has been documented for medium-voltage electrical cable with certain types of polyethylene and ethylene propylene rubber insulation. Water trees occur in hydrophobic polymers used as insulating materials when the materials are exposed to electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth of water trees is unpredictable and erratic. Water treeing is seen most often in cables operated at higher voltages; few occurrences have been documented in cables operated below 15 kV.

C.1.4 CIVIL DISCIPLINE AGING EFFECTS

The process to determine the aging effects applicable to structural components begins with a review of the aging effects identified in industry literature. From this set of aging effects, the Plant Hatch materials, operating environment (internal and external) and operating stresses serve to determine aging effects that need to be managed. Finally, the Plant Hatch-specific operating experience, industry-wide operating experience and CLB are reviewed to identify any additional aging effects that require aging management. This process provides reasonable assurance that the full set of aging effects was established for the aging management review.

To facilitate the identification of aging effects requiring management, the structural components have been grouped as follows:

- Structural Steel and Aluminum Components
- Concrete Components
- Structural Sealants
- Acrylic

Determination of the aging effects requiring management for each of these groups is presented in sections C.1.4.1 through C.1.4.4. The discussions address the applicable aging effects and the associated aging mechanism(s) that may cause the aging effect.

C.1.4.1 Structural Steel and Aluminum Components

The structural steel and aluminum components are grouped into commodities to efficiently perform the aging management reviews described in sections C.2.6.2 through C.2.6.6. The component types that make-up the commodity groups are collectively reviewed. As an aid to the reader, many of the component types included in these reviews are repeated here:

- Primary containment steel component types such as the containment shell plate, headers and downcomers, penetrations, bellows, bracing, supports, restraints, columns and saddles
- Building and structural steel component types such as beams, girders, columns, bracing, hangers, plate, and liner plate
- Miscellaneous structural steel and aluminum component types such as door frames, blow-out panels, tornado vent support frames, plate, sheet metal, penetrations, pipe, tubing, supports, grating, stairs, handrails, and various miscellaneous shapes
- Bolts and anchors such as structural bolts, cast in place bolts, expansion and wedge anchors

The component types are made from carbon steel, low alloy steel, galvanized steel, stainless steel and aluminum. The process for identifying the aging effects that require aging management was applied to the structural steel and aluminum components. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed in section C.1.1 of this appendix. In addition, sections C.1.2.1 through C.1.2.4 of this appendix further discuss steel in various water environments. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Loss of material due to general corrosion, pitting, crevice corrosion, and MIC.
- Cracking due to fatigue.

Loss of Material

General corrosion is characterized by an electrochemical reaction between a material and its environment. It normally proceeds uniformly, at a slow and predictable rate, over an entire surface area resulting in material dissolution or corrosion product buildup. At ordinary temperatures and neutral or near neutral media, both oxygen and moisture must be present to corrode steel. General corrosion is an applicable aging mechanism for uncoated carbon steels and high-strength low alloy steels. Stainless steel is very resistant to general corrosion. Loss of material by general corrosion is not an applicable aging effect for stainless steel.

Zinc coatings (or galvanizing) protect steel from general corrosion. The corrosion rate of zinc coatings depends on the type of ambient conditions involved. Factors such as the frequency and duration of moisture content, rate of drying, and the extent of industrial pollution have significant impact on the corrosion rate. Galvanized steel that is protected from acids, alkalis and atmosphere/weather is expected to have negligible corrosion rates. While the thickness of galvanizing was not specified for Plant Hatch, it is widely accepted that hot dipped galvanized steel will have a coating thickness of about 2.1 mils. The expected service life of such a coating should be about 50 years in an outside rural environment and over 60 years in an inside environment. However, in the absence of known galvanizing weights or coating thickness, an isolated or localized incidence of a loss of the zinc coating is plausible. Therefore, loss of zinc by general corrosion is an applicable aging effect for galvanized steel.

Pitting is an extremely localized corrosive attack in aqueous environments containing dissolved oxygen and chlorides. It is more common in austenitic (300 series) stainless than in carbon steels and aluminum. When passivity breaks down at a spot on a metal surface, an electrolytic cell is formed with the anode at the minute area of active metal, and the cathode at the considerable area of passive metal. The large electric potential difference between the two areas accounts for considerable flow of current with rapid corrosion at the anode. The anode does not spread because it is surrounded by passive metal, and as the mechanism continues it penetrates deeper into the metal forming a pit. Pitting is an applicable aging mechanism for uncoated structural steel and aluminum exposed to dissolved oxygen and chlorides in aqueous environments. This includes uncoated surfaces that are exposed to stagnant aqueous environments such as water pooling and where wet/dry conditions occur in the outside environment.

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It most frequently occurs in connections, lap joints, splice plates, bolt threads, under bolt heads, crevices adjacent to steel to concrete embedments and is associated with a stagnant solution (an electrolyte). The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. The crevice also retains moisture for a longer time than adjacent external surfaces, allowing a longer duration for corrosion damage to occur. The level of oxygen concentration in the electrolyte when present, is lower in the crevice making it anodic to surrounding areas in this differential oxygen cell and commencing active corrosion. The same cell is formed when the amount of oxygen reaching metal that is covered by rust or other insoluble reaction product is less than the amount that contacts other portions where the permeable coating is thinner or absent. Crevice corrosion is an applicable aging mechanism for structural steel and aluminum components where crevices that are exposed to stagnant solutions may exist.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. Galvanic corrosion will not occur in a dry environment. An electrolyte must be present and remain liquid. The ratio between surface areas of the metals in contact is of significant importance. Corrosion rates increase when the more noble metal has a greater surface area than the more active metal. Therefore, galvanic corrosion is an applicable aging mechanism for structural steel components exposed to wetted conditions and composed of two or more metals of differing electrochemical potential. Aluminum alloys are anodic to both carbon and stainless steels and would be preferentially corroded. Therefore galvanic attack is an applicable aging mechanism for aluminum alloy components at dissimilar metal welds.

Microbiologically influenced corrosion occurs by the action of microorganisms. Microorganisms are usually classified according to their ability to grow in the presence or absence of oxygen. Aerobic organisms grow in nutrient mediums containing dissolved oxygen. Anaerobic organisms grow most favorably in environments containing little or no oxygen. Selected aerobic organisms produce sulfuric acid by oxidizing sulfur or sulfur-bearing compounds. Selected anaerobic organisms reduce sulfate to sulfide ions, which influences both anodic and cathodic reactions on iron surfaces. These microscopic organisms have been observed to live in media with pH values between 0 and 11, temperatures between 30 °F and 180 °F, and under pressure up to 15,000 psi. MIC is facilitated by stagnant conditions, fouling internal crevices, and contact with untreated water from a natural source. Microorganisms such as iron bacteria are important in their effect on steel as they live by digesting iron and manganese ions into their cells. Iron bacteria flourish in running and stagnant water environments with temperatures of 40 °F to 100 °F and pH environments between 4 and 10. MIC is an applicable aging mechanism for structural steel and aluminum components that are submerged in water or saturated environments (e.g., soils) for long periods of time.

Cracking

Fatigue failure, in structural steel and steel components, is initiated by a plastic deformation in a localized region. A nonuniform stress distribution across a member cross-section may cause concentrated stresses to exceed the yield point within a small area of the cross-section resulting in a small plastic movement and a minute crack. The reduced cross-sectional area aggravates the stress distribution, which causes the crack to progress. After a relatively small number of stress cycles, a final, sudden fracture of the remaining cross-section occurs.

Generally, structural steel and steel components are not prone to fatigue. Loads, for the most part, are applied gradually and remain constant. Dynamic loads such as wind and seismic loads are too infrequent to initiate fatigue cracking. Members subjected to fatigue loading conditions such as crane runways are accounted for by code in their design. In addition, crane use is limited and the number of stress cycles experienced is low in terms of fatigue service life when considering the period of extended operation.

Thermal fatigue is a structural deterioration of material that can occur whenever expansion or contraction of a body resulting from change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the component and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. A review of the Plant Hatch CLB determined that fatigue is an applicable aging mechanism for certain primary containment, pressure boundary structural steel components.

C.1.4.2 Concrete Structural Components

The concrete structural components are grouped into a commodity to efficiently perform the aging management reviews described in section C.2.6.1. The component types that make-up the commodity group are collectively reviewed. As an aid to reader, many of the component types included in the review are repeated here:

- Masonry block walls
- Equipment foundations
- Floors, sumps and roofs
- Columns, slabs and beams
- Interior and exterior walls (above and below grade)

The component types are composed of concrete, reinforcing steel and grout. The process for identifying the aging effects that require aging management was applied to concrete structural components. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed section C.1.1 of this appendix. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Loss of material due to corrosion of embedded steel.
- Cracking in masonry block walls due to expansion or contraction.

Loss of Material Assessment

Corrosion of embedded steel is an electrochemical process that results in the formation of ferric oxide (rust). The corrosion products have a significantly greater volume than the original metal resulting in tensile stresses and spalling in the surrounding concrete. There are typically two types of embedded steel for concrete: reinforcing steel which is completely covered by concrete and steel which has a surface interface with the concrete such as embed plates or other structural steel members.

The high alkalinity (pH > 12.5) of concrete provides an environment around embedded steel which protects it from corrosion. If the pH is lowered (e.g., to 10 or less), corrosion may occur. However, the corrosion rate is still insignificant until a pH of 4.0 is reached. A reduction in pH can be caused by the leaching of alkaline products through cracks, the entry of acidic materials, or carbonation. Chlorides can be present in constituent materials of the original concrete mix (i.e., cement, aggregates, admixtures, and water), or they may be introduced environmentally. The severity of corrosion is influenced by the properties and type of cement and aggregates as well as the concrete moisture content.

The primary place that corrosion could occur is on the surface of Category I structures where moisture and oxygen may have access to the embedded steel. As discussed in C.1.4.1, embedded steel at the surface of the concrete is susceptible to crevice corrosion cracking. Corrosion products have a volume greater than the original metal. The presence of corrosion products subjects concrete to tensile stress, eventually causing hairline cracking, followed by rust staining and spalling. Exterior concrete components that are exposed to an aggressive environment on an ongoing basis are susceptible to embedded steel corrosion. Therefore, corrosion of embedded steel at the surface of the concrete is an applicable aging mechanism.

The degree to which concrete will provide satisfactory protection for steel reinforcement depends in most instances on the quality of the concrete and the depth of concrete cover over the steel. The permeability of the concrete is also a major factor affecting corrosion resistance. Concrete of low permeability contains less water under a given exposure and is more likely to have lower electrical conductivity and better resistance to corrosion. Such concrete also resists absorption of salts and their penetration into the embedded steel and provides a barrier to oxygen, an essential element of the corrosion process. Low water-to-cement ratios and adequate air entrainment increase resistance to water penetration and thereby provide greater resistance to corrosion.

The concrete structures and structural members at Plant Hatch are designed and constructed in accordance with ACI and ASTM standards that provide a good quality, dense, low permeability concrete that provides adequate concrete cover over the embedded reinforcing steel. As such, corrosion of embedded reinforcing steel is not an applicable aging mechanism for concrete structures and structural members exposed to interior environments and atmosphere/weather. However, if the concrete is degraded by other mechanisms, which reduce the protective cover of the steel reinforcement, corrosion may occur. Aggressive chemical attack is not a concern for the concrete components that are exposed to concentrations of chlorides that are less than 500 ppm, for concentrations of sulfates that are less than 1500 PPM, and for a pH of 5.5 or greater. At Plant Hatch, the ground water and river water chemistry are well within these limits.

Cracking

Expansion or contraction may result in cracking of masonry block walls whenever any restraint is imposed that will prevent the wall from free expansion or contraction. Restraint against expansion generally results in small stresses as compared with the strength of the block wall materials and thus rarely causes degradation of the masonry block wall. Restraints against free contraction are much more likely to cause significant tensile stresses. If these tensile stresses exceed the tensile strength of the unit, the bond strength between the mortar and the unit, or the shearing strength of the horizontal mortar joint, cracks will occur to relieve the stresses.

Expansion or contraction of masonry block walls may be caused by changes in temperature, changes in moisture content of the constituent materials, contraction due to carbonation, and/or movement of adjacent structural components. Therefore, cracking of masonry block walls is an applicable aging effect for block walls within the reactor building, control building, and main stack.

C.1.4.3 Structural Sealants

The structural sealants are grouped into a commodity to efficiently perform the aging management reviews described in section C.2.6.7. The sealant types that make-up the commodity group are collectively reviewed. As an aid to the reader, the sealant types included in the review are repeated here:

- Joint and caulk sealant in the joints between the exterior precast panels for the reactor buildings
- Main control room environmental control system duct gaskets and flex connectors.

The component types are composed of nonmetallic inorganic elastomers, elastomers, and nonasbestos synthetic fibers.

The process for identifying the aging effects was applied to structural sealants. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed in section C.1.1 of this appendix. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Material property changes and cracking due to thermal exposure
- Loss of adhesion due to exposure to excessive moisture

Material Property Changes and Cracking

Material property changes may occur in sealants and sealant materials that are continually exposed to temperatures above 95º F. A drying or curing effect causes the more volatile chemicals in the sealant to evaporate. As the material composition changes, the material becomes stiffer and exhibits a temporary increase in strength, but will eventually result in less elastic behavior and an overall loss of strength. Exposed surfaces of the sealants become harder and exhibit brittleness and loss of elasticity. When the materials are subjected to tension or compression forces, in the event of expansion or contraction, cracking may occur. Therefore, thermal exposure is an applicable aging mechanism for the structural sealants.

Loss of Adhesion

Exposure to excessive moisture may cause the sealant to pull away or separate from the surfaces to which it is mated. The quality of the bond is dependent on the ability of the adhesive to adhere to the surface to which it is bonded. Degradation of the bond is caused when a moisture agent, such as water, permeates the surface discontinuities that naturally occur in most materials, and begins to destroy the bond between the sealant and the mating surface. The sealant will begin to exhibit peeling and loss of bonding to the mating surface. Exposure to excessive moisture is an applicable aging mechanism for the structural sealants.

C.1.4.4 Acrylic

The tornado vent assembly domes are made of acrylic, and are evaluated in section C.2.6.8. The acrylic is Plexiglas G cellcast acrylic polymer. The chemical name is polymethyl methacrylate composed of carbon, hydrogen, and oxygen. No fillers are added as part of the forming process and material contains no significant halogens or sulfur. The process for identifying the aging effects was applied to the acrylic. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed in section C.1.1 of this appendix. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Cracking

Cracking Assessment

Cracking of the acrylic dome on the tornado roof vent assemblies is due to weathering, since the domes are exposed to the outside.

C.1.5 INDUSTRY OPERATING EXPERIENCE REVIEW

The systematic evaluation of environments and materials to identify those aging effects requiring management in the renewal term for the renewal term is presented in appendix C, section C.1. This evaluation was performed using information developed based on available industry knowledge. A review of pertinent generic industry operating experience, as contained in NRC generic communications, was a part of the process for determining aging effects requiring management. The generic communications listed in table C.1.5-1 were evaluated as part of the process, the results of which are contained in this section for the various materials and environments combinations at Plant Hatch.

Table C.1.5-1 Generic Communications Reviewed as Part of the Systematic Evaluation to Determine Aging Effects Requiring Management

Circular	80-007	Problems with HPCI Turbine Oil System
Circular	80-011	Emergency Diesel Generator Lube Oil Cooler Failures
Generic Letter	83-026	Clarification of Surveillance Requirements for Diesel Fuel Impurity Level Tests
Generic Letter	84-011	Inspections of BWR Stainless Steel Piping
Generic Letter	87-005	Potential Degradation of Mark I Drywells
Generic Letter	88-001 S1	NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping
Generic Letter	89-008	Erosion/Corrosion-Induced Pipe Wall Thinning
Generic Letter	89-013	Service Water System Problems Affecting Safety-Related Equipment
Generic Letter	91-013	Essential Service Water System Failures at Multi-Unit Sites
Generic Letter	91-017	Bolting Degradation or Failure in Nuclear Power Plants
IE Bulletin	81-003	Flow Blockage of Cooling Water to Safety System Components by Corbicula SP
Information Notice	79-023	Emergency Diesel Generator Lube Oil Coolers
Information Notice	80-005	Chloride Contamination of Safety-Related Piping and Components
Information Notice	81-021	Potential Loss of Direct Access to Ultimate Heat Sink
Information Notice	81-038	Potentially Significant Equipment Failures Resulting From Contamination of Air-Operated Systems
Information Notice	85-008	Industry Experience On Certain Materials Used In Safety-Related Equipment
Information Notice	85-030	Microbiologically Induced Corrosion of Containment Service Water System
Information Notice	85-034	Heat Tracing Contributes to Corrosion Failure of Stainless Steel Piping
Information Notice	85-056	Inadequate Environment Control for Components and Systems in Extended Storage or Lay-up
Information Notice	86-096	Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems
Information Notice	86-099	Degradation of Steel Containments
Information Notice	88-037	Flow Blockage of Cooling Water to Safety System Components
Information Notice	88-082, S1	Torus Shells With Corrosion and Degraded Coatings in BWR Containments

Table C.1.5-1 Generic Communications Reviewed as Part of the Systematic Evaluation to Determine Aging Effects Requiring Management (Continued)

Information Notice	89-007	Failures of Small Diameter Tubing in Control Air, Fuel, Oil, and Lube Oil Systems Render Emergency Diesels Inoperable
Information Notice	89-030	Excessive Drywell Temperatures
Information Notice	90-026	Inadequate Flow of Essential Service Water to Room Coolers and Heat Exchangers for Engineered Safety-Feature Systems
Information Notice	91-046	Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems
Information Notice	92-020	Inadequate Local Leak Rate Testing
Information Notice	92-081	Potential Deficiency of Electrical Cables with Bonded Hypalon Jackets
Information Notice	93-033	Potential Deficiency of Certain Class 1E Instrumentation and Control Cables
Information Notice	98-002	Nuclear Power Plant Cold Weather Problems and Protective Measures

C.2 AGING MANAGEMENT REVIEWS

Section C.2 of Appendix C provides an aging management summary for each unique structure, component, or commodity group at Plant Hatch determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management, aging management programs utilized to manage these aging effects, and a demonstration as to how the identified aging management programs manage aging effects requiring management using attribute tables. Section C.1 of the LRA provides discussion of aging effects and environments. Appendix A of the LRA provides descriptions of aging management programs required to manage aging effects requiring management.

C.2.1 AGING MANAGEMENT REVIEWS FOR CLASS 1 MECHANICAL DISCIPLINE COMMODITIES

C.2.1.1 Class 1 Components Environment Description

Class 1 components are subject to an environment of reactor water under normal conditions. The reactor water environment is defined in section C.1.2.1.

C.2.1.1.1 Aging Management Review for the Reactor Pressure Vessel

The reactor pressure vessel (RPV) consists of the following components:

- Shell and closure heads
- Nozzles, Appurtenances, and Penetrations
- Attachments and connecting welds (brackets and lugs)
- RPV head closure studs

The RPV and associated components are constructed from carbon steel, low alloy steel, austenitic stainless steel, and nickel based alloys.

Systems

B11 – Reactor Assembly (2.3.1.1)

Aging Effects Requiring Management

- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC) and fatigue.
- *Loss of fracture toughness* (C.1.2.1.3) due to neutron embrittlement.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Reactor Pressure Vessel (RPV) Monitoring Program* (A.1.17)
- *Component Cyclic or Transient Limit Program* (A.1.12)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Stress Corrosion Cracking

Reactor Water Chemistry Control serves to manage cracking due to SCC by controlling electrochemical corrosion potential (ECP) in accordance with the recommendations of EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *RPV Monitoring Program* is based upon the implementation of ASME Section XI, NUREG-0619, Generic Letter 88-01 as described in the ISI Program, as well as Boiling Water Reactor Vessel Internals Program (BWRVIP) requirements. The RPV Monitoring Program provides for volumetric, visual, and surface examinations of the RPV to provide adequate assurance that no significant crack initiation and growth has occurred. Additionally, it provides validation that the Reactor Water Chemistry Control Program is adequate to mitigate crack initiation and growth due to stress corrosion cracking within the RPV.

Management of Cracking due to Fatigue

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor (CUF) for several bounding locations within Class 1 components to verify that adequate margin against crack initiation and growth due to fatigue is maintained.

The *RPV Monitoring Program* provides for volumetric, visual, and surface examinations of the RPV to provide adequate assurance that no significant crack initiation and growth due to fatigue has occurred.

Management of Loss of Fracture Toughness due to Irradiation Embrittlement

Irradiation embrittlement is only applicable to beltline shell material and beltline weldments where the neutron fluence is greater than 1×10^{17} n/cm^2 for neutrons with energies greater than 1 MeV. Management of this aging effect is accomplished by the *RPV Monitoring Program* which provides guidelines for operation and inspection of the RPV in accordance with Appendices G and H of 10 CFR 50 and the BWRVIP. However, existing analyses at the time of application indicate that operation to 60 years is acceptable. See sections 4.6.1 and 4.6.2 of the LRA.

Review of Operating Experience

A review of the operating experience for both Hatch units indicates that there are no outstanding problems. Routine examinations as part of the ISI program and augmented in-vessel inspections, as well as normal maintenance and refueling activities have not revealed any age related issues for the reactor vessel. There was one instrument penetration that developed a leak attributed to IGSCC. The leak was detected as part of normal drywell outage activities and repaired. Corrosion was detected on the mating surface of the Unit 2 RPV head vent flange and repaired. Finally, during a routine maintenance activity, CRD flange bolts were found to have evidence of pitting. All CRD flange bolts were replaced and are inspected routinely upon disassembly.

Applicability of BWRVIP and Commitments to NRC Safety Evaluation Reports

The BWR Vessel and Internals Program (BWRVIP) developed inspection and evaluation reports for internals components and submitted them to NRC for review and approval. These inspection and evaluation reports address both the current term and license renewal. With regard to license renewal, the inspection and evaluation reports specifically addressed the internals relative to the requirements of the 10 CFR 54 regulations. The NRC is currently completing its review of the reports and issuing SERs to address the renewal term. These SERs establish the adequacy of the internals for renewal by concluding the rule provisions have been satisfied including the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstrating that these programs will assure the functionality of internals into the renewal term. The initial SERs impose the following requirements on a licensee adopting these reports for the renewal term:

- 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 BWRVIP report to manage the effects of aging on the functionality of the reactor vessel during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this BWRVIP report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel 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).
- 10 CFR 54.21(d) requires that a FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP report for a component shall ensure that the programs and activities specified as necessary in the BWRVIP document are summarily described in the FSAR supplement.
- 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In the BWRVIP report, the BWRVIP stated that there are no generic changes or additions to technical specifications associated with the component(s) as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing BWRVIP reports shall ensure that the inspection strategy described in the BWRVIP

document does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal.

This section evaluates the Hatch RPV attachments, nozzles, and penetrations against the above criteria and establishes the acceptability of those components for the license renewal term. In addition, TLAAs were also considered for the RPV. Those calculations and analyses meeting the criteria for TLAAs are addressed in section 4 of the LRA.

SNC has evaluated the BWRVIP for its applicability to the Hatch Units 1 and 2 design, construction and operating experience. SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design. The RPV components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operation parameters, including temperature, pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

- The components, which require aging management review in accordance with the rule, are covered by the BWRVIP reports.
- The BWRVIP reports cover all Hatch RPV and internals design.

Therefore, SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design and operation.

The applicable portions of the BWRVIP for the RPV implemented at Plant Hatch employs the BWRVIP as documented in the NRC Safety Evaluation Reports (SERs).

Table C.2.1.1-1 RPV BWRVIP Document Applicability[1]

Component	Reference
Shell and Heads	BWRVIP-74 (ref 1)
Nozzles (Including safe ends and thermal sleeves)	BWRVIP-74
Appurtenances	BWRVIP-74 ASME Section XI
Penetrations	BWRVIP-27 (ref 2)
Attachments and Connecting Welds Shroud support weld Jet Pump pad weld Closure studs and support skirt	BWRVIP-38 (ref 3) BWRVIP-41 (ref 4) BWRVIP-48 (ref 5) BWRVIP-74 (ref 1)

Notes:

1. The BWRVIP Documents listed are incorporated by reference into the Hatch LRA. Program commitments residing outside of the BWRVIP are excluded from this table.

Table C.2.1.1-2 Aging Management Program Assessment, RPV: Crack Initiation and Growth due to Stress Corrosion Cracking

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control and RPV Monitoring Program provide specific limitations and acceptance criteria related to operation and inspection of the RPV.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate cracking due to SCC by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The RPV Monitoring Program provides specific acceptance criteria related to cracking within the RPV.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RPV Monitoring Program provides for inspections and testing of RPV components on a set schedule approved by the NRC.
5. Monitoring and trending for timely corrective actions.	The RPV Monitoring Program provides for compilation of information concerning cracking of RPV components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control provides water chemistry parameters related to cracking within the RPV due to SCC. The RPV Monitoring Program provides detailed acceptance criteria for the RPV.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, and Reactor Pressure Vessel Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-3 Aging Management Program Assessment, RPV: Crack Initiation and Growth due to Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Component Cyclic or Transient Limit Program and RPV Monitoring Program provide specific limitations and acceptance criteria related to operation and inspection of the RPV.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of potentially hazardous fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Monitoring the actual CUF with the Component Cyclic or Transient Limit Program will give plant personnel the information needed to provide adequate assurance concerning the continued capability of the RPV to perform its intended function. The RPV Monitoring Program provides specific acceptance criteria related to cracking within the RPV.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RPV Monitoring Program provides a means for determining the amount of significant crack initiation or growth within the RPV due to thermal fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of the RPV. The RPV Monitoring Program provides for compilation of data concerning cracking of RPV components.
6. Acceptance criteria are included.	The RPV Monitoring Program and the Component Cyclic or Transient Limit Program provide detailed acceptance criteria related to the cracking of the RPV due to thermal fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Pressure Vessel Monitoring Program, and Component Cyclic or Transient Limit Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-4 Aging Management Program Assessment, RPV: Loss of Fracture Toughness due to Irradiation Embrittlement

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The RPV Monitoring Program provides specific limitations and acceptance criteria related to operation and inspection of the RPV.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The RPV Monitoring Program monitors parameters intended to manage loss of fracture toughness within RPV components.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RPV Monitoring Program provides a means for assuring that no loss of fracture toughness within the RPV initiated by irradiation embrittlement has occurred or is occurring.
5. Monitoring and trending for timely corrective actions.	The RPV Monitoring Program provides for compilation of information concerning loss of fracture toughness of RPV components.
6. Acceptance criteria are included.	The RPV Monitoring Program provides detailed acceptance criteria related to loss of fracture toughness within the RPV due to irradiation embrittlement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Reactor Pressure Vessel Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The RPV Monitoring Program provides a means for collection and analysis of industry wide operating experiences related to the RPV. The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.2 Aging Management Review for the Reactor Pressure Vessel Internals

The reactor pressure vessel internals requiring an aging management review consist of the following components:

- Shroud and repair hardware
- Shroud support
- Core spray spargers and internal piping
- Top guide - Unit 1 only (Unit 2 has wedges and will not lift even with completely cracked holddown assemblies)
- CRD housing and control rod guide tubes
- Jet pump assemblies

The reactor pressure vessel internals (RPV Internals) are constructed from carbon low alloy steel, cast, wrought, and forged austenitic stainless steels, and nickel based alloys.

Systems

B11 – Reactor Assembly (2.3.1.1)

Aging Effects Requiring Management

- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC) and fatigue

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Boiling Water Reactor Vessel Internals Program (BWRVIP)* (A.1.15)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Stress Corrosion Cracking

Reactor Water Chemistry Control serves to manage cracking due to SCC by controlling electrochemical corrosion potential (ECP) in accordance with the recommendations of EPRI BWR water chemistry guidelines." This can be accomplished through the use of filter / demineralizers which limit halides and other impurities within the feedwater and hydrogen injection which minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* and *BWRVIP* provide for detailed volumetric, surface, and visual examinations of RPV Internals, thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate stress corrosion cracking within the RPV Internals. ISI Program inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Cracking due to Fatigue

The *ISI Program* and *BWRVIP* provide for detailed volumetric, surface, and visual examinations of RPV Internals, thereby ensuring that no significant crack initiation and growth due to fatigue has occurred. ISI Program inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

The operating experience for the Hatch internals was reviewed. Over time there have been several occurrences of cracking, all of which have been repaired or are currently being monitored in accordance with prescribed procedures and programs. Early in life, IGSCC was detected on the Unit 1 core spray sparger. It was repaired by installation of a mechanical clamp. The sparger has been full-flow tested and the clamp examined afterwards with no evidence of degradation. Multiple indications have been detected over the years on the nonsafety related steam dryers. Some have been repaired while others are monitored. Jet pump inspections have resulted in minor indications associated with set-screw gaps, diffuser-to-adapter welds riser pipe welds and tack welds. These are being monitored and reexamined in accordance with the provisions of the BWRVIP. Crack-like indications were also detected in the core shrouds for both units. SNC conservatively decided to installed pre-emptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repair hardware and vertical welds are periodically examined as specified in the BWRVIP.

Applicability of BWRVIP and Commitments to NRC Safety Evaluation Reports

The BWR Vessel and Internals Program (BWRVIP) developed inspection and evaluation reports for internals components and submitted them to NRC for review and approval. These inspection and evaluation reports address both the current term and license renewal. With regard to license renewal, the inspection and evaluation reports specifically addressed the internals relative to the requirements of the 10 CFR 54 regulations. The NRC is currently completing its review of the reports and issuing SERs to address the renewal term. These SERs establish the adequacy of the internals for renewal by concluding the rule provisions have been satisfied including the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstrating that these programs will assure the functionality of internals into the renewal term. The initial SERs impose the following requirements on a licensee adopting these reports for the renewal term:

- 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 BWRVIP report to manage the effects of aging on the functionality of the reactor vessel during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this BWRVIP report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel 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).
- 10 CFR 54.21(d) requires that a FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP report for a component(s) shall ensure that the programs and activities specified as necessary in the BWRVIP document are summarily described in the FSAR supplement.
- 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In the BWRVIP report, the BWRVIP stated that there are no generic changes or additions to technical specifications associated with the components as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing BWRVIP reports shall ensure that the inspection strategy described in the BWRVIP document does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal."

This section evaluates the Hatch internals against the above criteria and establishes the acceptability of the internals for the license renewal term. In addition, TLAAs were also considered for the reactor vessel internals. Those calculations and analyses meeting the criteria for TLAAs are addressed in the TLAA section of this application.

SNC has evaluated the BWRVIP for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV internals components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operation parameters; including temperature, pressure, and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. Southern Nuclear has established that the BWRVIP reports bound the Hatch Units 1 and 2 design. SNC has determined the following:

- The components, which require aging management review in accordance with the rule, are covered by the BWRVIP reports.
- The BWRVIP reports cover all Hatch internals design.

Therefore, SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design and operation.

The BWRVIP for internals implemented at Plant Hatch employs the BWRVIP criteria as documented in the NRC Safety Evaluation Reports (SER).

Table C.2.1.1-5 RPV Internals BWRVIP Document Applicability[1,2]

Component	Reference
Shroud (including repair hardware)	BWRVIP-76 (Ref 6)
Shroud Support	BWRVIP-38 (Ref 3)
Core Spray Piping and Sparger	BWRVIP-18 (Ref 7)
Top Guide - Unit 1	BWRVIP-26 (Ref 8)
Control Rod Guide Tube	BWRVIP-47 (Ref 9)
Jet Pump Assembly	BWRVIP-41 (Ref 4)
CRD Housing	ASME Section XI
Dry Tube	ASME Section XI

Notes:

1. The BWRVIP Documents listed are incorporated by reference into the Hatch LRA. References to ASME Section XI are shown for completeness only and not included within BWRVIP commitments.
2. BWRVIP-76 is the incorporation of BWRVIP-01, BWRVIP-07, and BWRVIP-63 into one document.

Table C.2.1.1-6 Aging management Program Assessment, RPV Internals: Crack Initiation and Growth Due to Stress Corrosion Cracking[1]

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, ISI Program, and Boiling Water Reactor Vessel Internals Programprovide specific limitations and acceptance criteria related to operation and inspection of the RPV Internals.
2. Preventive actions to mitigate or prevent aging degradation.	The Reactor Water Chemistry Control is designed to mitigate cracking due to SCC by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Reactor Water Chemistry Control monitors ECP within the reactor water systems. This parameter is directly linked to mitigation of cracking due to SCC. The ISI Program and BWRVIP provide specific acceptance criteria related to cracking within the RPV Internals.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and BWRVIP provide for inspections and testing of the RPV Internals on a set schedule approved by the NRC.
5. Monitoring and trending for timely corrective actions.	Reactor Water Chemistry Control monitors and trends data to provide adequate assurance the quality of reactor grade water is maintained in accordance with industry standards. The ISI Program and BWRVIP provide for compilation of information concerning cracking of the RPV Internals.
6. Acceptance criteria are included.	Reactor Water Chemistry Control provides water chemistry parameters related to cracking within the RPV due to SCC. The ISI Program and BWRVIP provide detailed acceptance criteria for the RPV Internals.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	Reactor Water Chemistry Control provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies.
8. Confirmation process is included.	The ISI Program and BWRVIP provide confirmation that the current Reactor Water Chemistry Control in place is adequate to mitigate cracking within the RPV Internals during the period of extended operation.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Notes:

1. References to the BWRVIP in this table are shown for completeness only. Actual commitments to BWRVIP documents are contained in Table C.2.1.1-5.

Table C.2.1.1-7 Aging management Program Assessment, RPV Internals Crack Initiation and Growth Due to Fatigue[1]

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The BWRVIP and ISI Program provide specific acceptance criteria related to operation and inspection of the reactor pressure vessel internals.
2. Preventive actions to mitigate or prevent aging degradation.	None
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program and BWRVIP provide for inspections capable of detecting significant crack initiation and growth due to fatigue.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and BWRVIP provide a means for determining that no cracking within the reactor pressure vessel internals due to fatigue has occurred or is occurring.
5. Monitoring and trending for timely corrective actions.	The ISI Program and BWRVIP monitor parameters linked to crack initiation and growth due to fatigue of RPV Internals.
6. Acceptance criteria are included.	The BWRVIP and ISI Program provide detailed acceptance criteria related to the cracking of the reactor pressure vessel internals due to fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program provides a method for tracking and resolving deficiencies
8. Confirmation process is included.	The ISI Program and BWRVIP provide confirmation that no significant crack initiation or growth of the reactor pressure vessel internals due to fatigue has occurred or is occurring.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Notes:

1. References to the BWRVIP in this table are shown for completeness only. Actual commitments to BWRVIP documents are contained in Table C.2.1.1-5.

C.2.1.1.3 Aging Management Review for Class 1 Carbon Steel Components Within the Reactor Water Environment

This commodity group includes carbon steel components located within the Class 1 boundary and exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Flow nozzles
- Restricting Orifice

Systems

B21 – Nuclear Boiler System (2.3.1.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, erosion corrosion, and wear and fretting.
- *Cracking* (C.1.2.1.2) due to fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Galvanic Susceptibility Inspections* (A.3.1)
- *Component Cyclic or Transient Limit Program* (A.1.12)
- *Flow Accelerated Corrosion Program (FAC Program)* (A.2.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, and Crevice Corrosion

Reactor Water Chemistry Control serves to manage loss of material due to general corrosion, galvanic corrosion, pitting, and crevice corrosion by limiting conductivity, concentrations of impurities, and dissolved oxygen per EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers which limit halides and other impurities within the feedwater, and hydrogen injection, which minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for visual examinations of a representative number of components (such as pump casings and large bore valves) within this commodity group, thereby providing validation that the Reactor Water Chemistry Control Program is adequate to mitigate loss of material. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis to bound any potential loss of material due to galvanic corrosion.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating loss of material within carbon steel piping components by performing one time examinations of a sentinel population of pipe welds and associated heat affected zones.

Management of Loss of Material due to Wear and Fretting

The *ISI Program* provides for visual examinations of components within this commodity group determined to be susceptible to wear and fretting (such as large bore component flanges), thereby providing validation that any wear or fretting of component mating surfaces is negligible. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Material due to Erosion/Corrosion

The *FAC Program* provides for periodic volumetric examination of carbon steel piping components most susceptible to loss of material due to erosion corrosion. Results of inspections are analyzed in order to evaluate the requirements for future inspection locations. The FAC Program elements are based on EPRI recommendations for an effective flow accelerated corrosion program with additional inspections conducted to search for loss of material due to erosion corrosion within piping sections not considered susceptible to “FAC” according to the FAC model.

The *ISI Program* provides for visual examinations of components within this commodity group which may be susceptible to erosion/corrosion (such as pump casings and large bore valve bodies). These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Cracking due to Fatigue

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor for several bounding locations within Class 1 components to verify that adequate margin against cracking due to fatigue is maintained. This program is applicable to Class 1 components larger than NPS 1. No aging management program is required to manage fatigue of Class 1 components NPS 1 and under. Cracking of these components due to fatigue is managed through time limited aging analyses (See section 4.2.2 of the LRA).

The *ISI Program* provides for detailed surface and visual examinations of components within this plant commodity group, thereby ensuring that no significant crack initiation and growth due to thermal fatigue has occurred. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the B21 system. These deficiencies were screened to determine which ones might be potentially age-related. The age related deficiencies identified were determined to be the result of loss of material due to erosion corrosion. NRC Integrated Inspection Report 99-02 concluded that FAC inspections were conducted and evaluated in accordance with procedures, and the licensee had implemented an effective program to maintain high energy carbon steel piping systems within acceptable wall thickness limits.

Table C.2.1.1-8 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, and Crevice Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections provide for visual, surface, and volumetric inspections of components within this plant commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in carbon steel components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, the ISI Program, Galvanic Susceptibility Inspections, and Treated Water Systems Inspections provide detailed acceptance criteria related to the loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-9 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to Wear and Fretting

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program governs aging management for the components included within this plant commodity group susceptible to wear and fretting.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for visual inspections of components within this plant commodity group that would detect any significant loss of material due to wear and fretting.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the rate of material loss or degradation within components susceptible to wear and fretting.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in carbon steel components.
6. Acceptance criteria are included.	The ISI Program provides acceptance criteria for loss of material within mechanical closures.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program ensures that corrective and preventative actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-10 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to Erosion/Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The FAC Program and ISI Program govern aging management of erosion/corrosion related aging for Class 1 carbon steel components.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The FAC Program monitors wall thickness, hydraulic conditions, and process temperatures to estimate potential rates of material loss within susceptible components and systems. The ISI Program inspects surface conditions to provide adequate assurance that no loss of material due to erosion corrosion has occurred within valve bodies and pump casings.
4. The method of detection of the aging effects is described and performed in a timely manner.	The FAC Program provides for periodic inspections of components susceptible to erosion/corrosion and similar mechanisms. The ISI Program provides for periodic visual inspection of valve bodies and pump casings.
5. Monitoring and trending for timely corrective actions.	The FAC Program monitors and trends wall thickness degradation due to erosion/corrosion and similar mechanisms. ISI Program inspections require proper corrective actions be initiated any time an unacceptable condition is noted.
6. Acceptance criteria are included.	The FAC Program and ISI Program provide detailed acceptance criteria for loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, FAC Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-11 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Component Cyclic or Transient Limit Program and ISI Program govern aging management for cracking in the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of potentially hazardous fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Monitoring the actual CUF with the Components Cyclic or Transient Limit Program will give plant personnel the information needed to provide adequate assurance concerning the continued capability of Class 1 piping to perform its intended function. The ISI Program provides for inspections of components in this commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for determining the amount of significant crack initiation or growth within components due to thermal fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of components. The ISI Program provides for compilation of data concerning cracking of Class 1 components.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program and ISI Program provide detailed acceptance criteria related to the cracking of carbon steel components due to fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Component Cyclic or Transient Limit Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program Provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.4 Aging Management Review for Class 1 Wrought and Forged Stainless Steel Components Within the Reactor Water Environment

This commodity group includes wrought and forged austenitic stainless steel components located within the Class 1 boundary and exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping along with associated welds and weld overlays
- Valve bodies
- Thermowells
- Flow nozzles
- Crack growth monitor
- Restricting orifice

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- B31 – Reactor Recirculation (2.3.2.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to crevice corrosion and pitting.
- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC), intergranular attack (IGA), and fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Treated Water Systems Piping Inspections* (A.3.2)
- *Component Cyclic or Transient Limit Program* (A.1.12)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting and Crevice Corrosion

Reactor Water Chemistry Control serves to manage loss of material due to pitting, crevice corrosion, by limiting conductivity, impurities, and dissolved oxygen per EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for visual examinations of selected components within this commodity group (such as large bore valves), thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate loss of material due to pitting and crevice corrosion. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Since small bore Class 1 components are exempt from ASME Section XI and Generic Letter 88-01 inspections, a one time inspection of small bore, Class 1, stainless steel piping will be conducted via *Treated Water Systems Piping Inspections*. This activity will conduct appropriate examinations on a sentinel population of small-bore components to validate the adequacy of Reactor Water Chemistry Control.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Reactor Water Chemistry Control serves to manage cracking due to SCC and IGA by controlling electrochemical corrosion potential (ECP) in accordance with EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for detailed volumetric, surface, and visual examinations of components within this commodity group, thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate cracking due to SCC and IGA. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1 and Generic Letter 88-01 requirements included within the ISI Program.

Since small bore Class 1 components are exempt from ASME Section XI and Generic Letter 88-01 inspections, a one time inspection of small bore, Class 1, stainless steel piping will be conducted via *Treated Water Systems Piping Inspections*. This activity will conduct appropriate examinations on a sentinel population of small-bore components to validate the adequacy of Reactor Water Chemistry Control.

Management of Cracking due to Fatigue

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor for several bounding locations within Class 1 components to verify that adequate margin against cracking due to thermal fatigue is maintained. This program is applicable to Class 1 components larger than NPS 1. No aging management program is required to manage thermal fatigue of Class 1 components NPS 1 and under. Cracking of these components due to thermal fatigue is managed through time limited aging analyses (See section 4.2.2).

The *ISI Program* provides for detailed volumetric, surface, and visual examinations of components within this plant commodity group, thereby providing adequate assurance that no significant crack initiation and growth due to fatigue has occurred. Inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1 and Generic Letter 88-01 requirements included within the ISI Program.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21 and B31 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope B21 and B31 components, applicable to this plant commodity group, were found.

While no significant failure trends were found within the prior 5 years, the recirculation system piping has experienced significant age related degradation due to intergranular stress corrosion cracking (IGSCC) of weld heat affected zones. Specifically, the Unit 1 piping components have undergone extensive weld overlay repair and the Unit 2 piping has been replaced with 316NG stainless steel. The primary contributor to these IGSCC failures is dissolved oxygen content. Prior to initiation of hydrogen injection, higher levels of dissolved oxygen produced by radiolysis within the core region created an oxidizing environment conducive to IGSCC. Implementation of hydrogen water chemistry has effectively arrested existing IGSCC induced cracks and has prevented new cracks from forming. Therefore, the current *Reactor Water Chemistry Control* in conjunction with other mitigative activities has proven itself effective in mitigating failures by IGSCC.

Table C.2.1.1-12 Aging Management Program Assessment, Class 1 Wrought and Forged Stainless Steels Within the Reactor Water Environment: Loss of Material due to Pitting and Crevice Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, the ISI Program, and the Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program and Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections of components within this plant commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in stainless steel components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, Treated Water Systems Piping Inspections, and the ISI Program provide detailed acceptance criteria related to the loss of material within stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, ISI Program, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-13 Aging Management Program Assessment Class 1 Wrought and Forged Stainless Steels Within the Reactor Water Environment: Crack Initiation and Growth due to IGA and SCC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Reactor Water Chemistry Control, ISI Program, and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting impurities and dissolved oxygen content.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating cracking within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of information concerning cracking of stainless steel components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control provides detailed acceptance criteria related to the cracking within stainless steel components. The ISI Program and Treated Water Systems Piping Inspections provide acceptance criteria for cracking within selected components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, ISI Program, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-14 Aging Management Program Assessment, Class 1 Wrought and Forged Stainless Steels Within the Reactor Water Environment: Crack Initiation and Growth due to Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Component Cyclic or Transient Limit Program and ISI Program govern aging management for cracking in the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Component Cyclic or Transient Limit Program monitors plant events that could contribute to an increase in CUF, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for tracking the amount of significant crack initiation or growth within stainless steel components due to fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of components. The ISI Program provides for compilation of data concerning cracking of Class 1 components.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program and ISI Program provide detailed acceptance criteria related to the cracking of stainless steels due to fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Component Cyclic or Transient Limit Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.5 Aging Management Review for Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment

This commodity group includes cast austenitic stainless steel components located within the Class 1 boundary and exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Pump casings and covers
- Valve bodies

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- B31 – Reactor Recirculation (2.3.2.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to crevice corrosion, pitting, and wear and fretting.
- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC), intergranular attack (IGA), and fatigue.
- *Loss of fracture toughness* (C.1.2.1.3) due to thermal embrittlement

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Component Cyclic or Transient Limit Program* (A.1.12)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting and Crevice Corrosion

Reactor Water Chemistry Control serves to manage loss of material due to pitting and crevice corrosion by limiting conductivity, concentrations of impurities, and dissolved oxygen per EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for detailed examinations of large bore components within this commodity group (such as pump casings and valve bodies), thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate loss of material due to pitting and crevice corrosion. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Material due to Wear and Fretting

The *ISI Program* provides for detailed visual examinations of components within this commodity group determined to be susceptible to wear and fretting (such as large bore component flanges), thereby providing validation that any wear or fretting of component mating surfaces is negligible. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Because this not an aggressive aging effect, *Reactor Water Chemistry Control* serves to manage cracking due to SCC and IGA by controlling electrochemical corrosion potential (ECP) in accordance with the EPRI BWR water chemistry guidelines. This is accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

Management of Cracking due to Fatigue

Plant Hatch is committed to upgrading its Reactor Recirculation Pump shafts and covers to a later design to minimize the potential for thermal cycling and cracking due to thermal fatigue within the recirculation pump covers and integral heat exchangers.

Cracking of Byron Jackson recirculation pump covers has been observed in many plants since the early 1980's. This cracking is due to thermal cycling that occurs where process water and seal injection water mix. In response to this concern, Plant Hatch changed out the Unit 1 and 2 recirculation pump rotating assemblies and covers to an upgraded design in 1990 and 1991, respectively. Subsequently, Borg Warner / International Products determined that the new designs were still susceptible to cracking due to thermal cycling. To resolve this problem, Plant Hatch has committed to again, prior to entering the renewal period, replace the covers with the latest design, which incorporates a new heat exchanger design. Testing on this new design has not revealed any cracking due to thermal cycling.

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor for several bounding locations within Class 1 components to verify that adequate margin against cracking due to fatigue is maintained. Also, see section 4.2.2 of the application.

The *ISI Program* provides for surface and visual examinations of components within this plant commodity group, thereby ensuring that no significant crack initiation and growth due to fatigue has occurred. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Fracture Toughness Due to Thermal Embrittlement

The *ISI Program* provides for surface and visual examinations of components within this commodity group, thereby providing assurance that cracking of components as a result of loss of fracture toughness has not occurred. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21and B31 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope B21 and B31 components, applicable to this plant commodity group, were found.

Table C.2.1.1-15 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Loss of Material due to Pitting and Crevice Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control and the ISI Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity impurities and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for visual, surface, and volumetric inspections of components within this plant commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within cast stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in cast stainless steel components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control and the ISI Program provide detailed acceptance criteria related to the loss of material within stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, ISI Program, and Reactor Water Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-16 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Loss of Material due to Wear and Fretting

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program governs aging management for the components included within this plant commodity group susceptible to wear and fretting.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the rate of material loss or degradation within components susceptible to wear and fretting.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in stainless steel components.
6. Acceptance criteria are included.	The ISI Program provides acceptance criteria for loss of material within mechanical closures.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides adequate assurance that corrective and preventative actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-17 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to IGA and SCC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting impurities and dissolved oxygen content.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Reactor Water Chemistry Control sufficiently mitigates the aging effect such that this attribute is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	Reactor Water Chemistry Control sufficiently mitigates the aging effect such that this attribute is not required.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included.	Reactor Water Chemistry Control provides detailed acceptance criteria related to the cracking of stainless steels due to IGA and SCC.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Reactor Water Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventative actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-18 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to Thermal Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Component Cyclic or Transient Limit Program, and ISI Program govern aging management for cracking in the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of potentially hazardous fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Component Cyclic or Transient Limit Program monitors plant events that could contribute to an increase in CUF, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for determining the amount of significant crack initiation or growth within cast stainless steel components due to thermal fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of components. The ISI Program provides for compilation of data concerning cracking of Class 1 components.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program and ISI Program provide detailed acceptance criteria related to the cracking of cast stainless steels due to thermal fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Component Cyclic or Transient Limit Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-19 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Loss of Fracture Toughness due to Thermal Embrittlement

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program includes the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for periodic visual, surface, and volumetric inspections of Class 1 system components.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for determining that no loss of fracture toughness within cast stainless steel components due to thermal embrittlement has occurred or is occurring.
5. Monitoring and trending for timely corrective actions.	The ISI Program compiles data concerning inspection results for Class 1 components.
6. Acceptance criteria are included.	The ISI Program provides detailed acceptance criteria related to the loss of fracture toughness within stainless steels due to thermal embrittlement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.6 Aging Management Review for Class 1 Pressure Boundary Bolting

This commodity group includes Class 1 Pressure Boundary Bolting. This bolting is fabricated from low alloy carbon steel.

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- B31 – Reactor Recirculation (2.3.2.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.7.1) due to pitting and crevice corrosion.
- *Loss of preload* (C.1.2.7.2) due to embedment, gasket creep, thermal effects, and self-loosening.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Torque Activities* (A.1.11)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Preload

Torque Activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within Class 1 fasteners. These torque activities meet the intent of EPRI degradation and failure of bolting in nuclear power plants that was generally endorsed by the NRC in NUREG 1339, “Resolution of GSI 29.”

The *ISI Program* provides for volumetric and surface inspections of certain large diameter fasteners and visual inspection of bolted closure integrity via operating pressure testing. These inspections provide validation that improper preload has not caused a failure of the bolting. These inspections are conducted in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Material

The *ISI Program* provides for visual, surface, and volumetric inspections of Class 1 fasteners. These inspections are adequate to detect any significant loss of material due to corrosion within the fasteners. These inspections are conducted in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21 and B31 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope B21 and B31 components, applicable to this plant commodity group, were found. However, several instances of leaking bolted closures were found during pressure testing conducted prior to Drywell closure. These leaks were minor and in the majority of cases may be attributed to the thermal effects associated with cool-down of the Class 1 systems for outages. In all cases, these leaks were corrected in accordance with Plant Hatch's implementation of ASME Section XI within the ISI Program. Activities performed in accordance with vendor service information letters also contribute to the overall reduction of these leaks. Operating experience with CRD flange bolts indicates numerous instances of pitting and crevice corrosion. These conditions were discovered during ISI Program Inspections. All fasteners demonstrating evidence of corrosion were replaced.

Table C.2.1.1-20 Aging Management Program Assessment, Class 1 Pressure Boundary Bolting: Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-Loosening

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Torque Activities and ISI Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Torque Activities are designed to mitigate age-related degradation by controlling initial preload within bolted connections.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for visual and volumetric inspections of components within this plant commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the adequacy of current Torque Activities in preventing loss of preload within Class 1 fasteners during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of information concerning loss of preload within Class 1 fasteners.
6. Acceptance criteria are included.	The Torque Activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement. The ISI Program provides acceptance criteria for acceptable pressure test results.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Torque Activities, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-21 Aging Management Program Assessment, Class 1 Pressure Boundary Bolting: Loss of Material due to Crevice Corrosion and Pitting

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	Periodic inspections of Class 1 fasteners conducted in accordance with the ISI program are adequate to detect significant loss of material in a timely manner.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in Class 1 fasteners.
6. Acceptance criteria are included.	The ISI Program provides acceptance criteria for loss of material within Class 1 fasteners.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent reoccurrence.
8. Confirmation process is included.	The Corrective Actions Program ensures that corrective and preventative actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2 AGING MANAGEMENT REVIEWS FOR NON-CLASS 1 MECHANICAL DISCIPLINE COMMODITIES

C.2.2.1 Non-Class 1 Components Reactor Water Environment Description

Components within section C.2.2.1 are subject to an environment of reactor water under normal conditions. The reactor water environment is defined in section C.1.2.1.

C.2.2.1.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Reactor Water Environment

This commodity group includes carbon steel exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Steam traps
- Strainers
- Preheater
- Condenser shell

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- N61 – Main Condenser (2.3.5.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to general corrosion, galvanic corrosion, microbiologically influenced corrosion (MIC), crevice corrosion, pitting, and erosion corrosion.
- *Cracking* (C.1.2.1.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Flow Accelerated Corrosion Program (FAC Program)* (A.2.2)

- *Treated Water Systems Piping Inspections* (A.3.2)
- *Galvanic Susceptibility Inspections* (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management in the renewal term identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, and MIC

Reactor Water Chemistry Control serves to manage loss of material due to general corrosion, galvanic corrosion, pitting, crevice corrosion and MIC by limiting conductivity, impurities, and dissolved oxygen per the recommendations EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating loss of material within carbon steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Loss of Material due to Erosion Corrosion

The *FAC Program* provides for periodic volumetric examination of carbon steel piping components most susceptible to loss of material due to erosion corrosion. Results of inspections are analyzed in order to evaluate the requirements for future inspection locations. The FAC Program elements are based on EPRI recommendations for an effective flow accelerated corrosion program with additional inspections conducted to search for loss of material due to erosion corrosion within piping sections not considered susceptible to “FAC” according to the FAC model.

The *Treated Water Systems Piping Inspections* provide for one-time examination of carbon steel piping components most susceptible to loss of material due to erosion-corrosion.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the applicable system. These deficiencies were screened to determine which ones might be potentially age-related. Several failures of piping components downstream of orifices or other pressure reduction devices within steam systems were noted. In all cases the cause of the failure was attributed to erosion corrosion related to pressure fluctuations within the system. This experience validates the conclusion that erosion corrosion can occur in areas not identified by the FAC model. The *FAC Program* and *Treated Water Systems Piping Inspections* will specifically target these suspect areas for increased inspections such that future loss of component function is minimized. NRC Integrated Inspection Report 99-02 concluded that FAC inspections were conducted and evaluated in accordance with procedures, and the licensee had implemented an effective program to maintain high energy carbon steel piping systems within acceptable wall thickness limits.

Table C.2.2.1-1 Aging Management Program Assessment, Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Reactor Water Chemistry Control, Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections, and the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, the Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide detailed acceptance criteria related to the loss of material within carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.1-2 Aging Management Program Assessment: Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to Erosion Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The FAC Program and Treated Water Systems Piping Inspections govern aging management of erosion corrosion related aging for carbon steel components.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the FAC Program provides for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The FAC Program and Treated Water Systems Piping Inspections provide for periodic inspections of components susceptible to erosion corrosion and similar mechanisms.
5. Monitoring and trending for timely corrective actions.	The FAC Program monitors and trends wall thickness degradation due to erosion corrosion and similar mechanisms.
6. Acceptance criteria are included.	The FAC Program and Treated Water Systems Piping Inspections provide detailed acceptance criteria for loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, FAC Program, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program ensures that corrosion rates within erosion corrosion susceptible components are adequately identified and trended.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.1.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Reactor Water Environment

This commodity group includes wrought and forged austenitic stainless steel exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Thermowells
- Restricting orifices
- Preheater
- Steam Trap
- Strainer

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- N32 – Electro-Hydraulic Control (2.3.5.1)
- N61 – Main Condenser (2.3.5.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC), intergranular attack (IGA), and thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and MIC

Reactor Water Chemistry Control serves to manage loss of material due to pitting, crevice corrosion, or MIC by limiting conductivity, impurities and dissolved oxygen per the recommendations of the EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *Treated Water Systems Piping Inspections* serves to validate the adequacy of reactor water chemistry control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Reactor Water Chemistry Control serves to manage cracking due to stress corrosion cracking and intergranular attack by controlling electrochemical corrosion potential in accordance with the recommendations of the EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating cracking within stainless steel piping components by performing one-time examinations of a sentinel population of pipe welds and associated heat affected zones.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21, E41, E51, N32, and N61 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.1-3 Aging Management Program Assessment, Stainless Steel Components Within the Reactor Water Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control and the Treated Water Systems Piping Inspections govern aging management for the commodities included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Reactor Water Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Treated Water Systems Piping Inspections, and Reactor Water Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.1-4 Aging Management Program Assessment, Stainless Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to IGA and SCC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in preventing cracking within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the cracking of stainless steels due to IGA and SCC.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.2 Non-Class 1 Components Demineralized Water Environment Description

Components within section C.2.2.2 are subject to an internal environment of demineralized water under normal conditions. The demineralized water environment is defined in section C.1.2.2.

C.2.2.2.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Demineralized Water Environment

This commodity group includes carbon steel components and exposed to an internal environment of Demineralized Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Pump casings
- Accumulators
- Expansion Tank
- Thermowells

Systems

- C11 – Control Rod Drive (2.3.4.1)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T23 – Primary Containment (2.4.3)

Aging Effects Requiring Management

Loss of material (C.1.2.2.1) due to general corrosion, galvanic corrosion, microbiologically influenced corrosion (MIC), crevice corrosion, pitting, and erosion corrosion.

Cracking (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Treated Water Systems Piping Inspections* (A.3.2)
- *Galvanic Susceptibility Inspections* (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, MIC, and Crevice Corrosion

The *Demineralized Water and Condensate Storage Tank Chemistry Control* serves to manage loss of material due to pitting, crevice corrosion, or MIC by limiting concentrations of impurities, total organic carbon, and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and Condensate Storage Tank Chemistry Control implements EPRI BWR water chemistry guidelines.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating the loss of material within carbon steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

Management of Loss of Material due to Erosion Corrosion

The *Treated Water Systems Piping Inspections* provide for one-time examination of carbon steel piping components most susceptible to loss of material due to erosion-corrosion.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the C11, E41, E51, R43, and T23 systems. These deficiencies were screened to determine which ones might be potentially age-related. Several failures of piping components downstream of orifices or other pressure reduction devices within steam systems were noted. In all cases the cause of the failure was attributed to erosion corrosion related to pressure fluctuations within the system.

Table C.2.2.2-1 Aging Management Program Assessment, Carbon Steel Components Within the Demineralized Water Environment: Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control, the Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Demineralized Water and Condensate Storage Tank Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.2-2 Aging Management Program Assessment, Carbon Steel Components Within the Demineralized Water Environment: Loss of Material due to Erosion/Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Treated Water Systems Piping Inspections govern aging management of erosion corrosion related aging for carbon steel components.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide for periodic inspections of components susceptible to erosion corrosion and similar mechanisms.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included.	The Treated Water Systems Piping Inspections provide detailed acceptance criteria for loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.2.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Demineralized Water Environment

This commodity group includes stainless steel and cast austenetic stainless steel components exposed to an internal environment of demineralized water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Thermowells
- Restricting orifices
- Flex Hose

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- C11 – Control Rod Drive (2.3.4.1)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P11 – Condensate Transfer and Storage (2.3.4.5)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T23 – Primary Containment (2.4.3)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to crevice corrosion, pitting, and MIC.
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and MIC

The *Demineralized Water and Condensate Storage Tank Chemistry Control* serves to mitigate loss of material due to pitting, crevice corrosion, or MIC by limiting concentrations of detrimental impurities, and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and Condensate Storage Tank Chemistry Control implements EPRI BWR water chemistry guidelines.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating loss of material within stainless steels by performing appropriate examinations of a sentinel population of the susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.2-3 Aging Management Program Assessment, Stainless Steel Components Within the Demineralized Water Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this postion.
6. Acceptance criteria are included.	Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.2.3 Aging Management Review for Condensate Storage Tanks

This commodity group includes the Unit 1 and Unit 2 condensate storage tanks (CSTs). The Unit 1 tank is constructed of Type 6061-T6 aluminum alloy structural shapes and pipe and Type 5454-O aluminum alloy plate. Nozzle flanges are constructed from ASTM A181 Gr. 1 galvanized carbon steel. The Unit 2 tank is fabricated from wrought and forged austenitic stainless steels.

Systems

P11 – Condensate Transfer and Storage (2.3.4.5)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to galvanic corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Condensate Storage Tank Inspections* (A.3.4)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Galvanic Corrosion, Pitting, Crevice Corrosion, and MIC

The *Demineralized Water and Condensate Storage Tank Chemistry Control* serves to mitigate loss of material due to galvanic corrosion, pitting, crevice corrosion, or MIC by limiting concentrations of impurities and conductivity within the condensate storage tanks. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and Condensate Storage Tank Chemistry Control implements EPRI BWR water chemistry guidelines.

The *CST Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating loss of material. This activity provides for a one time internal inspection of both CSTs including creviced areas and dissimilar metal connections. Inspections conducted are similar to VT-1 examinations.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.2-4 Aging Management Program Assessment: Loss of Material Due to Galvanic Corrosion, MIC, Pitting, and Crevice Corrosion Within the Unit 1 and 2 Condensate Storage Tanks

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control and CST Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The CST Inspections provide for visual examination of CST internal surfaces.
4. The method of detection of the aging effects is described and performed in a timely manner.	The CST Inspections provide a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within the Unit 1 and 2 CSTs during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Demineralized Water and Condensate Storage Tank Chemistry Control and CST Inspections provide detailed acceptance criteria related to the loss of material within the Unit 1 and 2 CSTs.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and CST Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.3 Non-Class 1 Components Suppression Pool Water Environment Description

Components within section C.2.2.3 are subject to an environment of suppression pool water under normal conditions. The suppression pool water environment is defined in section C.1.2.2.

C.2.2.3.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Suppression Pool Environment

This commodity group consists of carbon steel commodities with an internal environment of suppression pool water or submerged within the suppression pool. The following component types are included within this evaluation:

- Piping
- Valve bodies
- Pump casings
- Thermowells
- Blind flange

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- T23 – Primary Containment (2.4.3)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, microbiologically influenced corrosion (MIC), and erosion corrosion.
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Suppression Pool Chemistry Control* (A.1.7)
- *Protective Coatings Program* (A.2.3)

- *Torus Submerged Components Inspection Program* (A.3.7)
- *Treated Water Systems Piping Inspections* (A.3.2)
- *Galvanic Susceptibility Inspections* (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, MIC, and Erosion/Corrosion

Suppression Pool Chemistry Control establishes the suppression pool water quality and chemistry acceptance criteria, and limits impurities, providing a degree of mitigation of these corrosion mechanisms. Suppression Pool Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

For components submerged within the suppression pool:

The *Torus Submerged Components Inspection Program* performs periodic inspections of piping and other components within this commodity group which are submerged within the suppression pool to assure that the necessary quality, operability, and safety limits of the systems' intended functions are not compromised by the loss of material. Inspections conducted are similar to VT-1 examinations.

For corrosion of external surfaces, the *Protective Coatings Program* conducts an underwater inspection of the protective coatings of underwater piping included in this commodity group which is submerged within the suppression pool and requires that coatings be repaired if found defective. The Protective Coatings Program is based on the recommendations of ANSI and ASTM coating standards for the nuclear power industry.

For other components (such as piping connected to the suppression pool):

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Suppression Pool Chemistry Control in mitigating the loss of material within small bore carbon steel piping by performing appropriate examinations of a sentinel population of susceptible locations within components that are not submerged.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A core spray jockey pump check valve experienced general corrosion to the point where the valve was replaced. The condition was identified as the result of the valve's disc being stuck in position. Thus, no loss of pressure boundary occurred.

RHR check valve internals were identified to have severe loss of material due to cavitation, pitting and erosion. This loss of material was not in the valve's body. The valve was repaired with plans made to replace the valve at the next outage.

Loop A of the RHR minimum flow piping developed a through wall leak. The leak was caused by a loss of material described as general wall degradation with one small distinguishable pit. A small portion of pipe containing the through wall leak was cut out of the line and evaluated for determination of the failure mechanism. It was reported that the hole initiated as a result of MIC and was then completed through ordinary inorganic corrosion. No MIC organisms were found in the cut sample of pipe or in any of several water samples taken from the RHR torus water chamber.

Further root cause analysis of this failure was conducted by Plant Hatch. Additional RHR piping components and a section of core spray minimum flow piping were analyzed. The results indicated that the RHR pipe wall thickness degradation was cause by ancient MIC intrusion of the minimum flow line and the carbon steel surfaces being immersed in stagnant, deoxygenated water. It has been concluded that this MIC intrusion was the result of the length of time it took to construct the plant and how pipe lay-up procedures were administered. The core spray minimum flow piping was reported to have general wall thinning on the bottom half of the entire twenty foot horizontal run of pipe and there was pitting on both sides of the pipe approximately halfway up the wall of the pipe. This damage was indicative of a partially filled piping system exposed to flow and/or standing water.

The corrective action consisted of replacing all pipe and several valves in the immediate vicinity of the through wall leak on RHR piping. It is assumed that the core spray piping removed for analysis was also replaced with new piping. The RHR issue was closed with no further actions required based on the evaluation of the results.

The results of the analysis of the damage to the RHR and core spray minimum flow lines are indicative of the aging mechanisms and the resulting aging effects identified above. Thus, the recommendations to perform internal inspection of the piping systems is substantiated.

Table C.2.2.3-1 Aging Management Program Assessment, Carbon Steel Components Submerged Within the Suppression Pool: Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, Erosion/Corrosion, and MIC.

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program, Torus Submerged Components Inspection Program, and Suppression Pool Chemistry Control govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities. The Protective Coatings Program minimizes loss of material by maintaining the applied surface coatings.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Protective Coatings Program provides for visual inspections, and the Torus Submerged Components Inspection Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program performs visual inspections of the protective coating for deterioration (blistering, peeling, etc.). The Torus Submerged Components Inspection Program provides for periodic visual inspection of component surfaces.
5.	Monitoring and trending for timely corrective actions.	The Protective Coatings Program requires evaluation, and documentation of the visual inspections of the coating program. The Torus Submerged Components Inspection Program provides for compilation of data and identification of trends concerning significant loss of material in submerged components.
6.	Acceptance criteria are included.	The Protective Coatings Program requires qualified coating specialists to evaluate visual inspection results of the internal surface protective coatings. Suppression Pool Chemistry Control establishes limits for impurities and conductivity. The TAIP provides detailed acceptance criteria related to the loss of material.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, Protective Coatings Program, and Torus Submerged Components Inspection Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-2 Aging Management Program Assessment, Carbon Steel Components Within the Suppression Pool Water Environment (but not submerged in the suppression pool): Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Suppression Pool Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this postion.
6. Acceptance criteria are included.	The Suppression Pool Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-3 Aging Management Program Assessment, Carbon Steel Components Within the Suppression Pool Water Environment: Loss of Material Due to Erosion/Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Treated Water Systems Piping Inspections govern aging management of erosion corrosion related aging for carbon steel components.
2. Preventive actions to mitigate or prevent aging degradation.	Due to the monitoring and trending activities and corrective actions, preventive actions are not specified for this commodity.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide for periodic inspections of components susceptible to erosion corrosion and similar mechanisms.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included.	The Treated Water Systems Piping Inspections provide detailed acceptance criteria for loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.3.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Suppression Pool Environment

This group consists of wrought/forged stainless steels and cast austenitic stainless steels with an internal environment of treated water and an external environment of inside or submerged in the suppression pool. Component types included in this commodity group include:

- Strainers
- Piping
- Valve Bodies
- Restricting Orifices
- Tubing
- Conductivity Element
- Thermowell

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.2.2) due to SCC, IGA and thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Suppression Pool Chemistry Control* (A.1.7)
- *Torus Submerged Components Inspection Program* (A.3.7)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Due to Crevice Corrosion, Pitting, and MIC

Suppression Pool Chemistry Control establishes the suppression pool water quality and chemistry acceptance criteria, and limits impurities, providing a degree of mitigation of these corrosion mechanisms. Suppression Pool Chemistry Control implements EPRI BWR water chemistry guidelines.

For Components Submerged with the Suppression Pool:

The *Torus Submerged Components Inspection Program* provides for periodic inspections of the HPCI and RCIC torus suction strainers and piping. This inspection is similar to VT-1 and adequate to detect large scale degradation of components located within the torus, thereby providing indications as to the adequacy of the chemistry program.

For Other Components (Such as Piping Connected to the Suppression Pool):

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to SCC and IGA

Cracking due to SCC and IGA applies only to SS components exposed to steam exhaust from SRVs, the HPCI turbine exhaust steam, or the RCIC turbine exhaust steam. *Suppression Pool Chemistry Control* establishes the suppression pool water quality and chemistry acceptance criteria, and limits impurities, providing a degree of mitigation of these corrosion mechanisms. The Suppression Pool Chemistry Control implements EPRI BWR water chemistry guidelines.

The *Torus Submerged Components Inspection Program* performs periodic inspections of piping within the suppression pool. This inspection is similar to VT-1 and adequate to detect large scale degradation of components located within the torus, thereby providing indications as to the adequacy of the chemistry program.

Management of Cracking Due To Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written on these systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of the in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.3-4 Aging Management Program Assessment, Stainless Steel Components Submerged Within the Suppression Pool: Loss of Material Due To Crevice Corrosion, Pitting, And MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Suppression Pool Chemistry Control and Torus Submerged Components Inspection Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Torus Submerged Components Inspection Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Torus Submerged Components Inspection Program provides a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The Torus Submerged Components Inspection Program provides for compilation of data and identification of trends concerning significant loss of material in submerged components.
6. Acceptance criteria are included.	Suppression Pool Chemistry Control and the Torus Submerged Components Inspection Program provide detailed acceptance criteria related to the loss of material within stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, and Torus Submerged Components Inspection Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-5 Aging Management Program Assessment, Stainless Steel Components Within the Suppression Pool Environment (but not submerged in the suppression pool): Loss of Material Due To Crevice Corrosion, Pitting, And MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Suppression Pool Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Suppression Pool Chemistry Control provides detailed acceptance criteria related to the loss of material within stainless steels. The Treated Water Systems Piping Inspections provides acceptance criteria for loss of material within stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-6 Aging Management Program Assessment, Stainless Steel Components Submerged Within the Suppression Pool: Cracking Due to SCC and IGA

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control and Torus Submerged Components Inspection Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by controlling fluid purity and composition.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Torus Submerged Components Inspection Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Torus Submerged Components Inspection Program provides a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating cracking within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The Torus Submerged Components Inspection Program provides for compilation of information concerning degradation of stainless steel components.
6. Acceptance criteria are included.	Suppression Pool Chemistry Control provides detailed acceptance criteria related to the loss of material within stainless steels. The Torus Submerged Components Inspection Program provides acceptance criteria for degradation of stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, and Torus Submerged Components Inspection Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.4 Non-Class 1 Components Borated Water Environment Description

Components within section C.2.2.4 are subject to an environment of borated water under normal conditions. The borated water environment is described in section C.1.2.2.

C.2.2.4.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Borated Water Environment

This commodity group includes carbon steel components exposed to an internal environment of borated water and includes only the standby liquid control system ASME Section VIII accumulators. The inner surfaces of these accumulators are coated with a phenolic resin.

Systems

C41 – Standby Liquid Control (2.3.3.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to general corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Protective Coatings Program* (A.2.3)
- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Pitting, Crevice Corrosion, and MIC

The *Protective Coatings Program* provides for periodic inspection of the phenolic resin coating on the interior surfaces of the accumulator. Provided this coating remains intact, no aging of the accumulator surfaces is expected due to the excellent protective properties provided by the coating material.

Demineralized Water and Condensate Storage Tank Chemistry Control serves to mitigate loss of material within the standby liquid control system accumulators by minimizing the contaminants to which the phenolic resin liner is exposed.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable system. These deficiencies were screened to determine which ones might be potentially age-related. No significant age-related failures of in-scope components, applicable to this plant commodity group, were found. However, isolated instances of foreign material intrusion were noted and corrected via the *Corrective Actions Program*.

Table C.2.2.4-1 Aging Management Program Assessment, Carbon Steel Components Within the Borated Water Environment: Loss of Material due to General Corrosion, Pitting, Crevice Corrosion, and MIC.

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program and Demineralized Water and Condensate Storage Tank Chemistry Control govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities. The Protective Coatings Program minimizes loss of material by maintaining the applied inner surface coating.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program provides a means to perform visual inspection of the accumulator's internal protective coating for deterioration (blistering, peeling, etc.).
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program requires evaluation, and documentation of the visual inspections of the applied coating.
6. Acceptance criteria are included.	The Protective Coatings Program requires qualified coating specialists to evaluate visual inspection results of the internal surface protective coatings. Demineralized Water and Condensate Storage Tank Chemistry Control provides detailed acceptance criteria related to the loss of material.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides a means for control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides a means for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.4.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Borated Water Environment

This commodity group includes stainless steel components exposed to an internal environment of borated water. The following component types are included within this evaluation:

- Storage tank
- Piping
- Valve bodies
- Thermowells
- Pump casing

Systems

C41 – Standby Liquid Control (2.3.3.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Treated Water Systems Piping Inspections* (*A.3.2*)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and MIC

Demineralized Water and Condensate Storage Tank Chemistry Control serves to mitigate loss of material due to pitting, crevice corrosion, or MIC by limiting detrimental impurities, and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and

Condensate Storage Tank Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found. However, isolated instances of foriegn material intrusion were noted and corrected via the Corrective Actions Program.

Table C.2.2.4-2 Aging Management Program Assessment, Stainless Steel Components Within the Borated Water Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	The Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.5 Non-Class 1 Components Closed Cooling Water Environment Description

Closed cooling water is used within the reactor building closed cooling water (RBCCW) system and primary containment chilled water (PCCW) system. A description of closed cooling water is provided in section C.1.2.3.

C.2.2.5.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Closed Cooling Water Environment

This commodity group includes carbon steel components exposed to an internal environment of closed cooling water. The following component types are included within this evaluation:

- Piping
- Valve bodies
- Heat exchanger shells.

Systems

- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P64 – Primary Containment Chilled Water (2.3.4.10)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.3.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, erosion/corrosion, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.3.2) due to thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Closed Cooling Water Chemistry Control* (A.1.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, MIC, and Erosion Corrosion

Closed Cooling Water Chemistry Control establishes and maintains closed cooling water chemistry in accordance with EPRI closed cooling water chemistry guidelines. Closed cooling water is pH adjusted into the basic range and corrosion inhibitors are added to promote an adherent protective oxide layer and minimize corrosion. Biocides are added to minimize microbiologically influenced corrosion. Levels of detrimental impurities and microbiological organisms are monitored and trended. Corrosion coupons are utilized to provide indications of general corrosion rates.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Closed Cooling Water Chemistry Control in mitigating loss of material within carbon steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue:

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience:

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the P42 and P64 systems. These deficiencies were screened to determine which ones might be potentially age-related. Minimal age-related deficiencies of the in-scope P42 and P64 components were found. Failures related to general corrosion of carbon steel valve bodies exposed to condensation and leakage. Insulated and uninsulated external surfaces are addressed in section C.2.4.1.

Closed cooling water (CCW) system chemistry at Plant Hatch has become very complex over the years. Originally there were fewer systems to analyze and not many chemical analyses were performed. Now there are 11 systems and 14 different analyses (plus coupons on RBCCW). Significant changes in the sampling and analysis program have been made based on internally identified deficiencies.

Table C.2.2.5-1 Aging Management Program Assessment, Carbon Steel Components Within the Closed Cooling Water Environment: Loss of Material Due to General Corrosion, Galvanic Corrosion, Erosion corrosion, Crevice Corrosion, Pitting, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Closed Cooling Water Chemistry Control is designed to mitigate age-related degradation by maintaining closed cooling water chemistry in accordance with EPRI guidelines.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Closed Cooling Water Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Closed Cooling Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.5.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Closed Cooling Water Environment

This commodity group includes stainless steel components exposed to an internal environment of closed cooling water. The following component types are included within this evaluation:

- Thermowells
- Piping
- Valve bodies
- Flexible connectors
- Flow elements

Systems

- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P64 – Primary Containment Chilled Water (2.3.4.10)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.3.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.3.2) due to thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Closed Cooling Water Chemistry Control* (A.1.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Crevice Corrosion, Pitting, and MIC

Closed Cooling Water Chemistry Control establishes and maintains closed cooling water chemistry in accordance with EPRI closed cooling water chemistry guidelines. Closed cooling water is pH adjusted into the basic range and corrosion inhibitors are added to promote an adherent protective oxide layer and minimize corrosion. Biocides are added to minimize microbiologically influenced corrosion. Levels of detrimental impurities and microbiological organisms are monitored and trended. Corrosion coupons are utilized to provide indications of general corrosion rates.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Closed Cooling Water Chemistry Control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the P42 and P64 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related deficiencies of the in-scope P42 and P64 components, applicable to this plant commodity group, were found.

Closed cooling water (CCW) system chemistry at Plant Hatch has become very complex over the years. Originally there were fewer systems to analyze and not many chemical analyses were performed. Now there are 11 systems and 14 different analyses (plus coupons on RBCCW). Significant changes in the sampling and analysis program have been made based on internally identified deficiencies.

Table C.2.2.5-2 Aging Management Program Assessment, Stainless Steel Components Within the Closed Cooling Water Environment: Loss of Material Due to Pitting, Crevice Corrosion, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Closed Cooling Water Chemistry Control is designed to mitigate age-related degradation by maintaining closed cooling water chemistry in accordance with EPRI guidelines.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Closed Cooling Water Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6.	Acceptance criteria are included.	Closed Cooling Water Chemistry Control and the Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Closed Cooling Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.5.3 Aging Management Review for Non-Class 1 Copper Alloy Components Within the Closed Cooling Water Environment

This commodity group includes copper alloys exposed to an internal environment of closed cooling water. The following component types are included within this evaluation:

- End caps
- Relief valve bases
- Piping
- Temperature probes

Systems

- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P64 – Reactor Building Chilled Water System (2.3.4.10)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.3.1) due to selective leaching and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.3.2) due to thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Closed Cooling Water Chemistry Control* (A.1.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Selective Leaching and Microbiologically Influenced Corrosion

Closed Cooling Water Chemistry Control establishes and maintains closed cooling water chemistry in accordance with EPRI closed cooling water chemistry guidelines. Closed cooling water is pH adjusted into the basic range and corrosion inhibitors are added to promote an adherent protective oxide layer and minimize corrosion. Biocides are added to minimize microbiologically influenced corrosion. Levels of detrimental impurities and microbiological organisms are monitored and trended. Corrosion coupons are utilized to provide indications of general corrosion rates.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Closed Cooling Water Chemistry Control in mitigating loss of material within copper alloy piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the P42 and P64 systems. These deficiencies were screened to determine which ones might be potentially age-related. Minimal age-related deficiencies of the in-scope P42 and P64 components were found.

The closed cooling water chemistry program has extensive operating history demonstrating quality improvements made based on past problems. The Hatch Chemistry Program description contains a discussion of this history.

Closed cooling water (CCW) system chemistry at Plant Hatch has become very complex over the years. Originally there were fewer systems to analyze and not many chemical analyses were performed. Now there are 11 systems and 14 different analyses (plus coupons on RBCCW). Significant changes in the sampling and analysis program have been made based on internally identified deficiencies.

Table C.2.2.5-3 Aging Management Program Assessment, Copper Alloy Components Within the Closed Cooling Water Environment: Loss of Material Due to Selective Leaching and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Closed Cooling Water Chemistry Control is designed to mitigate age-related degradation by maintaining closed cooling water chemistry in accordance with EPRI guidelines.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide for detection of loss of material in brass components.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Closed Cooling Water Chemistry Control and the Treated Water Systems Piping Inspections provide detailed acceptance criteria related to loss of material in brass components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Closed Cooling Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6 Non-Class 1 Components River Water Environment Description

River water consists of water taken directly from the Altamaha River for use as cooling water for various systems. See section C.1.2.4 for a description of the river water environment.

C.2.2.6.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the River Water Environment

This commodity group includes carbon steel components exposed to an internal environment of river water. The following component types are included within this evaluation:

- Piping
- Valve bodies
- Strainer bodies
- Discharge venturies
- Sight glass bodies
- Thermowells
- Pump discharge columns
- Pump discharge heads

Systems

- W33 – Traveling Water Screen, Trash Racks (2.3.4.16)
- P41 – Plant Service Water (2.3.4.7)
- E11 – Residual Heat Removal (2.3.3.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.4.1) due to general corrosion, galvanic corrosion, erosion corrosion, crevice corrosion, pitting, microbiologically influenced corrosion (MIC), and fouling.
- *Cracking* (C.1.2.4.2) due to thermal fatigue.
- *Flow blockage* (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)

- *Structural Monitoring Program* (A.2.5)
- *Galvanic Susceptibility Inspections* (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Thermal Fatigue:

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Management of Loss of Material and Flow Blockage

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program performs systematic and periodic inspection of plant service water and residual heat removal system components to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

PSW and RHRSW Chemistry Control provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *Galvanic Susceptibility Inspections* provides for a one-time examination of carbon steel to stainless steel dissimilar metal welds to evaluate the extent of loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that 15 deficiencies on E11 and 155 deficiencies on P41 systems were found.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-1 Aging Management Program Assessment, Carbon Steel Components Within the River Water Environment: Loss of Material Due to General Corrosion, Galvanic Corrosion, Crevice Corrosion, Erosion Corrosion MIC, Pitting, and Fouling

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, Structural Monitoring Program, and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Chemical additions conducted in accordance with PSW and RHRSW Chemistry Control serve to inhibit growth of microorganisms. Inspections of the intake pits conducted in accordance with the Structural Monitoring Program serve to minimize particulate intrusion into service water systems.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections; the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections; and the Structural Monitoring Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program and Galvanic Susceptibility Inspections provide for periodic inspections of carbon steel components.
5.	Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for trending of data related to loss of material in carbon steel components.
6.	Acceptance criteria are included.	The PSW and RHRSW Inspection Program, Galvanic Susceptibility Inspections, Structural Monitoring Program, and PSW and RHRSW Chemistry Control provide acceptance criteria related to loss of material in carbon steel components.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, PSW and RHRSW Inspection Program, Structural Monitoring Program, PSW and RHRSW Chemistry Control, and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-2 Aging Management Program Assessment, Carbon Steel Components Within the River Water Environment: Flow Blockage Due to Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Chemistry Control, PSW and RHRSW Inspection Program, and Structural Monitoring Program, govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, PSW and RHRSW Inspection Program, Structural Monitoring Program, PSW and RHRSW Chemistry Control, and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the River Water Environment

This commodity group includes stainless steel and cast austenitic stainless steel components with an internal environment of river water. The following component types are included within this evaluation:

- Piping
- Tubing
- Restricting orifices
- Thermowells
- Strainer baskets
- Flexible connectors
- Valve bodies
- Pump bowl assemblies
- Site glass body

Systems

- E11 – Residual Heat Removal System (2.3.3.2)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.4.1) due to crevice corrosion, pitting, microbiologically influenced corrosion (MIC), and fouling.
- *Cracking* (C.1.2.4.2) due thermal fatigue;
- *Flow blockage* (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material and Flow Blockage

PSW and RHRSW Chemistry Control provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program performs systematic and periodic inspection of plant service water and residual heat removal system components to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps located in the intake structure. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

Management of Cracking due to Thermal Fatigue:

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that 15 deficiencies on E11 and 155 deficiencies on P41 systems were found. These deficiencies were screened to determine which ones might be potentially age-related. No age related failures found.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-3 Aging Management Program Assessment, Stainless Steel Components Within the River Water Environment: Loss of Material Due to Crevice Corrosion, MIC, Pitting, and Fouling

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and Structural Monitoring Program govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Chemical additions conducted in accordance with PSW and RHRSW Chemistry Control serve to inhibit growth of microorganisms. Inspections of the intake pits conducted in accordance with the Structural Monitoring Program serve to minimize silt and debris intrusion into service water systems.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for periodic inspections of stainless steel components.
5.	Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for trending of data related to loss of material in stainless steel components.
6.	Acceptance criteria are included.	The PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to loss of material in stainless steel components.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-4 Aging Management Program Assessment, Stainless Steel Components within the River Water Environment: Flow Blockage Due to Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Inspection Program, Structural Monitoring Program, and PSW and RHRSW Chemistry Control govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup on compound surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, the Structural Monitoring Program, and the PSW and RHRSW Chemistry Control provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6.3 Aging Management Review for Non-Class 1 Copper Alloys Within the River Water Environment

This commodity group includes copper alloy components with an internal environment of river water. The following component types are included within this evaluation:

- Instrumentation tubing
- Valves.

Systems

- E11 – Residual Heat Removal (2.3.3.2)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- Loss of material (C.1.2.4.1) due to selective leaching, galvanic corrosion, microbiologically influenced corrosion (MIC), fouling, and erosion corrosion
- Cracking (C.1.2.4.2) due to thermal fatigue
- Flow Blockage (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1. or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material and Flow Blockage

PSW and RHRSW Chemistry Control provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps located in the intake structure. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program performs systematic and periodic inspection of plant service water and residual heat removal system components to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that no age-related failures, relative to this plant commodity group, were noted in the past five years.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-5 Aging Management Program Assessment, Copper Alloys Within the River Water Environment: Loss of Material due to Selective Leaching, Galvanic Corrosion, Crevice Corrosion, Pitting, MIC, Erosion Corrosion, and Fouling

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, Structural Monitoring Program, and PSW and RHRSW Chemistry Control govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Chemical additions conducted in accordance with PSW and RHRSW Chemistry Control serve to inhibit growth of microorganisms. Inspections of the intake pits conducted in accordance with the PSW and RHRSW Inspection Program and Structural Monitoring Program serve to minimize silt and debris intrusion into service water systems.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for periodic inspections of copper alloys.
5.	Monitoring and trending is included for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for trending of data related to loss of material in copper alloys.
6.	Acceptance criteria are included	The PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to loss of material within copper alloys.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management programs, including past corrective actions resulting in program enhancements or additional programs are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-6 Aging Management Program Assessment, Copper and Alloys Within the River Water Environment: Flow Blockage Due to Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Structural Monitoring Program, PSW and RHRSW Inspection Program, and PSW and RHRSW Chemistry Control govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup and silt dispersant to minimize buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. The PSW and RHRSW Inspection Program examines inscope components for evidence of flow blockage. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and Structural Monitoring Program provide for monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6.4 Aging Management Review for Non-Class 1 Gray Cast Iron Components Within the River Water Environment

This commodity group includes gray cast iron components with an internal environment of river water. The following component types are included within this evaluation:

- Strainers

Systems

P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- Loss of material (C.1.2.4.1) due to crevice corrosion, pitting, general corrosion, microbiologically influenced corrosion (MIC), selective leaching, erosion corrosion, galvanic corrosion, and fouling.
- Cracking (C.1.2.4.2) due to thermal fatigue.
- Flow blockage (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material and Flow Blockage

PSW and RHRSW Chemistry Control Program provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW Systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program outlines the steps necessary to perform systematic and periodic inspection of plant service water and residual heat removal system piping to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps located in the intake structure. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience:

A review of the condition reporting database mentioned in section 3.0 showed that approximately 155 deficiencies had been written on the P41 system. These deficiencies were screened to determine which ones might be potentially age related. No age related failures were found for the in-scope components covered by this AMR.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-7 Aging Management Program Assessment, Gray Cast Iron Components Within the River Water Environment Loss of Material Due to Crevice, Pitting, General and Galvanic Corrosion, Selective leaching, MIC, Erosion Corrosion and Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Chemistry Control, PSW and RHRSW Inspection Program, and Structural Monitoring Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program providesfor monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-8 Aging Management Program Assessment, Gray Cast Iron Components Within the River Water Environment Flow Blockage due to Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Chemistry Control, PSW and RHRSW Inspection Program, and Structural Monitoring Program, govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup and silt dispersant to minimize buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.7 Non-Class 1 Components Fuel Oil Environment Description

Components within section C.2.2.7 are subject to an environment of fuel oil under normal conditions. The fuel oil environment is described in section C.1.2.5.

C.2.2.7.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Fuel Oil Environment

This commodity group includes carbon steel exposed to an internal environment of fuel oil. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- EDG transfer pump
- EDG day tanks
- EDG storage tanks
- EDG transfer pump discharge head

Systems

Y52 – Fuel Oil (2.3.4.19)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.5.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, and MIC.
- *Cracking* (C.1.2.5.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Diesel Fuel Oil Testing* (A.1.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Diesel Fuel Oil Testing provides for sampling and analysis of fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to assure that no significant buildup of contaminants exists. If excessive contamination does occur, the program provides for draining and cleaning of the tank as required to reestablish and maintain acceptable contaminant levels. Fuel oil is also tested for proper viscosity and specific gravity, thereby detecting any significant degradation of the fuel oil within the storage tank. Acceptance criteria for fuels oil quality is established by Applicable ASTM standards (see Appendix A.1.3).

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. Deficiencies related to the diesel fuel oil supply system were limited to five instances of unacceptable sediment and water levels within the EDG Storage Tanks. Acceptable levels were regained promptly via the *Corrective Actions Program*.

One deficiency related to diesel fuel oil testing was noted. The back up sample results for total particulate did not agree with the primary sample. Chemistry procedures were revised to prevent recurrence.

The Nuclear Plant Reliability Data System (NPRDS) was used to chronicle information on plant operating experiences. The results of the NPRDS search demonstrate the extremely low incidence of failure of components exposed to fuel oil. Further, the search did not identify any incidents of corrosion in these systems.

Information Notice 91-46 indicates that several plants have experienced clogging of strainers with sediment and degraded fuel oil. *Diesel Fuel Oil Testing* provides management of this concern at Plant Hatch as described above.

Table C.2.2.7-1 Aging Management Program Assessment, Carbon Steel Components Within the Fuel Oil Environment: Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Diesel Fuel Oil Testing governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Diesel Fuel Oil Testing is designed to mitigate age-related degradation of EDG Fuel Oil Supply System components.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
6. Acceptance criteria are included.	Diesel Fuel Oil Testing provides detailed acceptance criteria related to the loss of material within carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	Diesel Fuel Oil Testing provides for analyses of significant events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.7.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Fuel Oil Environment

This commodity group includes stainless steel components exposed to an internal environment of fuel oil. The following component types are included within this evaluation:

- Piping
- Flexible hose
- Strainer baskets
- Valve bodies

Systems

Y52 – Fuel Oil (2.3.4.19)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.5.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.5.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Diesel Fuel Oil Testing* (A.1.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Diesel Fuel Oil Testing provides for sampling and analysis of fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to assure that no significant buildup of contaminants exists. If excessive contamination does occur, the program provides for draining and cleaning of the tank as required to reestablish and maintain acceptable contaminant levels. Fuel oil is also tested for proper viscosity and specific gravity, thereby detecting any significant degradation of the fuel oil within the storage tank. Acceptance criteria for fuels oil quality is established by applicable ASTM standards (see Appendix A.1.3).

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related.

One deficiency related to diesel fuel oil testing was noted. The back up sample results for total particulate did not agree with the primary sample. Chemistry procedures were revised to prevent recurrence.

The Nuclear Plant Reliability Data System (NPRDS) was used to chronicle information on plant operating experiences. The results of the NPRDS search demonstrate the extremely low incidence of failure of components exposed to fuel oil. Further, the search did not identify any incidents of corrosion in these systems.

Information Notice 91-46 indicates that several plants have experienced clogging of strainers with sediment and degraded fuel oil. Diesel Fuel Oil Testing provides management of this concern at Plant Hatch as described above.

Table C.2.2.7-2 Aging Management Program Assessment, Stainless Steel Components Within the Fuel Oil Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Diesel Fuel Oil Testing provides aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Diesel Fuel Oil Testing is designed to mitigate age-related degradation of EDG Fuel Oil Supply System components.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
5.	Monitoring and trending for timely corrective actions.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
6.	Acceptance criteria are included.	Diesel Fuel Oil Testing provides detailed acceptance criteria related to the loss of material within stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	Diesel Fuel Oil Testing provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assume that corrective actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.8 Non-Class 1 Components Dry Compressed Gas Environment Description

Components evaluated within this section have an internal environment of dried gases. See section C.1.2.6 for a description of the dried gas environment.

C.2.2.8.1 Aging Management Review for Non-Class 1 Carbon Steel Components in the Dry Compressed Gas Environment

This commodity group includes carbon steel components exposed to an internal environment of dried gas. Component types included in this commodity group include:

- Accumulator
- Piping
- Flanges
- Filter housings
- Valve bodies
- Regulator

Systems

- C11 – Control Rod Drive (2.3.4.1)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

None Required.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

Operating experience related to cracking of these components due to thermal fatigue is incorporated into the design assumptions of the ASME codes to which the components were designed. The operating experience for Plant hatch does not indicate a failure due to this mechanism.

C.2.2.8.2 Aging Management Review for Non-Class 1 Stainless Steel Components in the Dry Compressed Gas Environment

This commodity group includes stainless steel components exposed to an internal environment of dried gas. Component types included in this commodity group include:

- Air Receiver
- Piping
- Flexible hoses
- Rupture discs
- Valve bodies
- Vaporizers
- Pressure buildup coils
- Gas accumulators
- Nitrogen storage tank
- Filter housings

These components are constructed from stainless steel.

Systems

- C11 – Control Rod Drive (2.3.4.1)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

None required.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

Operating experience related to cracking of these components due to thermal fatigue is incorporated into the design assumptions of the ASME codes to which the components were designed. The operating experience for Plant hatch does not indicate a failure due to this mechanism.

C.2.2.8.3 Aging Management Review for Non-Class 1 Copper Alloy Components in the Dry Compressed Gas Environment

This commodity group includes copper alloy components exposed to an internal environment of dried gas. Component types included in this commodity group include:

- Tubing
- Valve bodies

These components are constructed from copper alloys: copper, brass, and bronze.

Systems

- C11 – Control Rod Drive (2.3.4.1)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

None required.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

Operating experience related to cracking of these components due to thermal fatigue is incorporated into the design assumptions of the ASME codes to which the components were designed. The operating experience for Plant hatch does not indicate a failure due to this mechanism.

C.2.2.9 Humid and Wetted Gases Environment Evaluation

The gases internal to these components are humid or wet, containing sufficient entrained moisture to enable pooling of liquid at low or especially cool locations. The humid gas environment is described in section C.1.2.6.

C.2.2.9.1 Aging Management Review for Non-Class 1 Carbon Steel and Cast Iron Components in the Humid or Wetted Gases Environment

This commodity group includes carbon steel and cast iron components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping and ductwork
- Flexible Connectors
- Filter housings
- Valve bodies
- Flanges
- Diesel fuel oil storage tank man-way shell
- HPCI pump turbine pressure boundary components
- RCIC pump turbine pressure boundary components
- Louvers
- Thermowells
- Nitrogen tank jacket
- Strainer
- Steam trap

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- C11 – Control Rod Drive (2.3.4.1)
- E11 – Residual Heat Removal (2.3.3.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T23 – Primary Containment (2.4.3)
- T46 – Standby Gas Treatment (2.3.3.6)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)
- T49 – Post-LOCA Hydrogen Recombiners (2.3.3.8)
- X41 – Outside Structures HVAC (2.3.4.17)

- Y52 – Fuel Oil (2.3.4.19)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.6.1) due to general corrosion, selective leaching, pitting, crevice corrosion, galvanic corrosion, and microbiologically influenced corrosion (MIC)
- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to general Surface, Pitting, Crevice, Galvanic, and Microbiologically Influenced Corrosion

Corrosion mechanisms will be detected for these components through a *Gas Systems Component Inspections*. This activity will involve appropriate inspections of a representative sample of the most likely component locations.

The *Passive Component Inspection Activities* provides for inspections, similar to VT-1, of component surfaces anytime an applicable component is opened for periodic maintenance or repair. This information is carefully evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-1 Aging Management Program Assessment, Carbon Steel and Cast Iron Components Containing Humid or Wetted Gases: Loss of Material due to Pitting, Crevice, Galvanic, and Microbiologically Influenced Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Passive Component Inspection Activities and Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Passive Component Inspection Activities provide for compilation of data and identification of trends concerning significant loss of material in gas system components.
6. Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for corrosion in carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Passive Component Inspection Activities, and Gas Systems Component Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.9.2 Aging Management Review for Non-Class 1 Stainless Steel Components Containing Humid or Wetted Gases

This commodity group includes stainless steel components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping
- Valve bodies
- Strainers
- Restricting orifices
- Steam traps
- Flexible connectors
- Rupture discs
- Thermowells
- Accumulators
- Radiation elements

These components are constructed from stainless steel.

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P33 – Post-Accident Sampling (2.3.4.6)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T23 – Primary Containment (2.4.3)
- T41 – Reactor Building HVAC (2.3.4.15)
- T46 – Standby Gas Treatment (2.3.3.6)
- T48 – Primary Containment Purge and Inerting System (2.3.3.7)
- T49 – Post-LOCA Hydrogen Recombiners (2.3.3.8)
- X41 – Outside Structures HVAC (2.3.4.17)
- Y52 – Fuel Oil (2.3.4.19)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- Loss of Material (C.1.2.6.1) due to pitting, crevice corrosion, and microbiologically influenced corrosion (MIC).
- Cracking (C.1.2.6.2) due to thermal fatigue, stress corrosion cracking (SCC) and intergranular attack (IGA).

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and Microbiologically Influenced Corrosion

Corrosion mechanisms will be detected for these components through a one-time *Gas Systems Component Inspection*. This activity will involve inspections of a representative sample of the most likely component locations subject to humid or wetted gases.

The *Passive Component Inspection Activities* provides for periodic visual examinations, similar to VT-1, of passive component interior surfaces subject to wetted gases. This program will identify and find any significant aging effects occurring within components in this plant commodity group.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Interior cracking mechanisms will be detected for these components through the *Passive Components Inspection Activities* and the one-time *Gas Systems Component Inspections*. These activities will involve appropriate inspections of a representative sample of the component locations where pooling of liquid is most likely.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures due to loss of material or cracking of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-2 Aging Management Program Assessment, Stainless Steel Components Containing Humid or Wetted Gases: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Passive Component Inspection Activities and Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5.	Monitoring and trending for timely corrective actions.	The Passive Component Inspection Activities provide for compilation of data and identification of trends concerning significant loss of material in gas system components.
6.	Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for corrosion in stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.9-3 Aging Management Program Assessment, Stainless Steel Components Containing Humid or Wetted Gases: Crack Initiation and Growth Due to IGA and SCC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Gas Systems Component Inspections and Passive Component Inspection Activities govern aging management for the components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The inspections used in Gas Systems Component Inspections and Passive Component Inspection Activities are adequate to identify cracking in gas system stainless steel prior to significant degradation.
5. Monitoring and trending for timely corrective actions.	The Gas Systems Component Inspections Activities and Passive Component Inspection Activities provide for monitoring and trending of degradation in gas system components.
6. Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for SCC and IGA in stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.9.3 Aging Management Review for Non-Class 1 Copper Alloy Components Containing Humid or Wetted Gases

This commodity group includes copper alloy components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping and tubing
- Valve bodies

These components are constructed from copper or brass.

Systems

- C11 – Control Rod Drive (2.3.4.1)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T41 – Reactor Building HVAC (2.3.4.15)
- T46 – Standby Gas Treatment (2.3.3.6)
- X41 – Outside Structures HVAC (2.3.4.17)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- Loss of Material (C.1.2.6.1) due to selective leaching, pitting, crevice corrosion, MIC, and galvanic corrosion.
- Cracking (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Management of Loss of Material due to Selective Leaching, Pitting, Crevice Corrosion, MIC, and Galvanic Corrosion

Evidence of interior corrosion mechanisms will be detected for these components through a one-time *Gas Systems Component Inspections*. This activity will involve inspections of a representative sample of the most likely component locations.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the C11, R43, T41, T46, X41, and Z41 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures due to loss of material or cracking of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-4 Aging Management Program Assessment, Copper Alloy Components Containing Humid or Wetted Gases: Loss of Material due to Selective leaching or due to Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5. Monitoring and trending for timely corrective actions.	Since corrosion in these systems is expected to be minimal, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	The Gas Systems Component Inspections include acceptance criteria for corrosion in copper alloys.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Gas Systems Component Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.9.4 Aging Management Review for Non-Class 1 Galvanized Carbon Steel and Aluminum Components Containing Humid or Wetted Gases

This commodity group includes galvanized carbon steel and aluminum components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping
- Ductwork
- Filter housing
- Duct silencer
- Duct heater

Systems

- R43 – Emergency Diesel Generator (2.3.4.12)
- T41 – Reactor Building HVAC (2.3.4.15)
- T46 – Standby Gas Treatment (2.3.3.6)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.6.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, and MIC. For this section, this aging effect applies to the R43 piping for the emergency diesel generator exhausts, the Z41 aluminum duct heater, and Z41 ductwork mounted outside the control building.
- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Management of Loss of Material due to General Surface and Galvanic Corrosion

Evidence of corrosion mechanisms will be detected for these components through *Gas Systems Component Inspections*. This activity will involve inspections of a representative sample of the most likely component locations subject to humid or wetted gases.

The *Passive Component Inspection Activities* provides for inspections, similar to VT-1, of the emergency diesel generator exhausts and ductwork on the control building roof anytime an applicable component is opened for periodic maintenance or repair. This information is carefully evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the R43, T41, T46, and Z41 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures due to loss of material or cracking of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-5 Aging Management Program Assessment, Galvanized Carbon Steel and Aluminum Components Containing Humid or Wetted Gases: Loss of Material due to General Surface, Galvanic Corrosion, Crevice Corrosion, Pitting, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Passive Component Inspection Activities and Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Passive Component Inspection Activities provide for compilation of data and identification of trends concerning significant loss of material in gas system components.
6. Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for corrosion in galvanized carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.10 Non-Class 1 Pressure Boundary Bolting Evaluation

Pressure Boundary Bolting within section C.2.2.10 are subject to inside and outside environments at Plant Hatch. Only bolting pertaining to piping connections are evaluated by this section. Bolting supplied by vendors as part of valves, pumps, strainers, etc. are not subject to an aging management review. Section C.1.2.7 of the LRA includes an analysis of aging effect determinations for bolting materials at Plant Hatch.

C.2.2.10.1 Aging Management Review for Non-Class 1 Bolting Materials

This commodity group includes carbon steel pressure boundary bolting. This bolting is fabricated from carbon and low alloy carbon steel fabricated to the requirements of ASTM A-307 (Grade B), ASME SA 194 (Grade 2H), and ASME SA 193 (Grade B7).

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- C11 – Control Rod Drive (2.3.4.1)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- N61 – Main Condenser (2.3.5.2)
- P41 – Plant Service Water (2.3.4.7)
- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P52 – Instrument Air (2.3.4.9)
- P64 – Primary Containment Chill Water (2.3.4.10)
- P70 – Drywell Pneumatic (2.3.4.11)
- T23 – Primary Containment (2.4.3)
- T41 – Reactor Building HVAC (2.3.4.15)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)
- T49 – Post LOCA Hydrogen Removal (2.3.3.8)
- W33 – Traveling Water Screens, Trash Racks (2.3.4.16)
- X41 – Outside Structures HVAC (2.3.4.17)
- X43 – Fire Protection (2.3.4.18)
- Y52 – Fuel Oil (2.3.4.19)
- Z41 – Control Room HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.7.1) due to general corrosion of carbon steel fasteners in the inside environment and general corrosion, pitting, crevice corrosion, and MIC in the outside environment.
- *Loss of Preload* (C.1.2.7.2) due to embedment, gasket creep, thermal effects, and self-loosening.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Programs To Manage Aging Effects:

- *Torque Activities* (A.1.11)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-loosening

Torque Activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of guidelines for preload within non-Class 1 fasteners. These torque activities meet the intent of EPRI guidelines for degradation and failure of bolting in nuclear power plants that were generally endorsed by the NRC in NUREG 1339, “Resolution of GSI 29.”

Management of Loss of Material due to General Corrosion

Since some fasteners may be susceptible to general corrosion, the *Protective Coatings Program* provides for periodic inspection of component external surfaces, including fasteners. This program will also provide for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces).

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. Numerous instances of bolted joint failure due to loss of preload were noted during regular system walk-downs and *ISI Program* mandated pressure testing. Many instances of degradation due to general corrosion were also noted during regular system surveillance activities. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.2.10-1 Aging Management Program Assessment for Non-Class 1 Carbon Steel Bolting Materials Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-Loosening

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Torque Activities governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Torque Activities are designed to mitigate age-related degradation by controlling initial preload within bolted connections.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
6. Acceptance criteria are included.	The Torque Activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Torque Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.10-2 Table Aging Management Program Assessment for Non-Class 1 Carbon Steel Bolting Materials Loss of Material due to General Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program is designed to mitigate age-related degradation by specifying recommended grades of protective coatings, and surface preparation requirements.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program provides for periodic inspection of components within this commodity group to ensure no significant degradation due to general corrosion has occurred.
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program provides for monitoring and trending of deficiencies.
6. Acceptance criteria are included.	The Protective Coatings Program provides acceptance criteria for applied coatings systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a process for identifying deficient conditions and ensuring proper corrective action is taken.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.10.2 Aging Management Review for Non-Class 1 Stainless Steel Bolting Materials

This commodity group includes stainless steel pressure boundary bolting.

Systems

- C41 – Standby Liquid Control (2.3.3.1)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P11 – Condensate Transfer and Storage (2.3.4.5)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)
- X41 – Outside Structures HVAC (2.3.4.17)

Aging Effects Requiring Management

- *Loss of preload* (C.1.2.7.2) due to embedment, gasket creep, thermal effects, and self-loosening.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Programs To Manage Aging Effects:

- *Torque Activities* (A.1.11)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Management of Loss of Preload

Torque Activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. These torque activities meet the intent of EPRI guidelines for degradation of bolting in nuclear power plants.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. Numerous instances of bolted joint failure due to loss of preload were noted during regular system walk-downs and *ISI Program* mandated pressure testing. Many instances of degradation due to general corrosion were also noted during regular system surveillance activities. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.2.10-3 Aging Management Program Assessment for Non-Class 1 Stainless Steel Bolting Materials Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-Loosening

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Torque Activities governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Torque Activities are designed to mitigate age-related degradation by controlling initial preload within bolted connections.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
6. Acceptance criteria are included.	The Torque Activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Torque Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.11 Non-Class 1 Heat Exchanger Evaluation

The residual heat removal system heat exchangers are fabricated from several different materials and are exposed to multiple fluid environments. Therefore, these heat exchangers are evaluated in a separate commodity group.

C.2.2.11.1 Aging Management Review for Residual Heat Removal Heat Exchangers

The residual heat removal system heat exchangers provide a method for removing heat from the reactor pressure vessel or suppression pool. These heat exchangers include the following components:

- Tubes – stainless steel
- Shell, Shell Nozzles, and Shell Internals – carbon steel
- Channel Assembly (including channel head, water box, and partition plate) – carbon steel
- Tube Sheet – carbon steel with stainless steel cladding on raw water side surfaces and carbon steel on torus water side
- Impingement Plate – stainless steel

Systems

- E11 – Residual Heat Removal (2.3.3.3)

Aging Effects Requiring Management

- *Cracking* (C.1.2.1.2 and C.1.2.4.2) due to stress corrosion cracking and intergranular attack of stainless steel components and vibration induced fatigue.
- *Loss of Material* (C.1.2.1.1 and C.1.2.4.1) due to general corrosion, galvanic corrosion crevice corrosion, pitting, MIC, and fouling.
- *Loss of Heat Exchanger Performance* (C.1.2.4.4) due to corrosion product buildup, silting, and macroorganism intrusion.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Programs To Manage Aging Effects:

- *RHR Heat Exchanger Augmented Inspection and Testing Program* (A.3.6)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Suppression Pool Chemistry Control* (A.1.7)
- *Plant Service Water and RHR Service Water Chemistry Control* (A.1.4)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Stress Corrosion Cracking, Intergranular Attack, and Vibration Induced Cracking

The *RHR Heat Exchanger Augmented Inspection and Testing Program* provides for the following combination of inspections and tests as applicable to manage Cracking due to Stress Corrosion, Intergranular Attack, and Vibration Induced Fatigue.

- Visual inspections are performed at scheduled intervals of the internal surfaces of the Heat Exchanger Channel and Shell sides. These inspections are performed in accordance with the *Plant Service Water and RHR Service Water Inspection Program*.
- Eddy Current tests are performed at scheduled intervals and whenever leaks are suspected in tubes and/or tube sheets.
- Leak Testing is performed to detect leaks in tubes and/or tube sheet whenever leaks are suspected.

The *Inservice Inspection Program* provides volumetric and surface examinations of the RHR Heat Exchanger shell circumferential welds, shell head circumferential welds, and nozzle to shell welds in accordance with ASME Section XI, 1989, Table IWC 2500-1 code.

The program is implemented to detect any flaws and cracking in these welds and in ½ inch of the base material from the toe of the weld. Therefore, by performing this program, cracking of the pressure retaining weld and half (1/2) inch of the base material is managed.

The *Suppression Pool Chemistry Control* serves to minimize SCC and IGA for shell side stainless steel surfaces. This program provides for low limits on halogen content and conductivity, thereby providing control of SCC and IGA for shell side surfaces; i.e., impingement plate and outer surface of the tubes.

Management of Loss of Material

Carbon steel components may experience loss of material due to general corrosion, galvanic corrosion, pitting, crevice corrosion, erosion corrosion, silting and corrosion product buildup, debris intrusion, and MIC.

Stainless steel components and cladding may experience loss of material due to crevice corrosion, pitting, silting and corrosion product buildup, debris intrusion, and MIC.

The *Suppression Pool Chemistry Control* serves to minimize loss of material for shell side surfaces. This program provides for low limits on halogen content and conductivity, thereby providing mitigation of corrosion on these surfaces.

The *Plant Service Water and RHR Service Water Chemistry Control* provides for addition of biocides in order to lower the potential for MIC, and MAC within raw water system components. These additions serve to reduce the potential for significant loss of material due to corrosion within the RHR Heat Exchangers.

The *RHR Heat Exchanger Augmented Inspection and Testing Program* provides for the following combination of inspections and tests as applicable to manage loss of material.

- Visual inspections are performed at scheduled intervals of the internal surfaces of the Heat Exchanger Channel and Shell sides. These inspections are performed in accordance with the *Plant Service Water and RHR Service Water Inspection Program*.
- Eddy Current tests are performed at scheduled interval and whenever leaks are suspected in tubes and/or tube sheets.
- Leak Testing is performed to detect leaks in tubes and/or tube sheet whenever leaks are suspected.

The *Inservice Inspection Program* provides for volumetric and surface examinations of the RHR Heat Exchanger shell circumferential welds, shell head circumferential welds and nozzle to shell welds in accordance with ASME Section XI, 1989, Table IWC 2500-1 Code.

The program is implemented to detect any flaws and loss of material in these welds and in ½ inch of the base material from the toe of the weld. Therefore, by performing this program, cracking of the pressure retaining weld and half (1/2) inch of the base material is managed.

The *Structural Monitoring Program*, by preventing build up of foreign material in the intake structure, prevents macroorganisms or silt to be carried to Heat Exchanger Components, thereby preventing formation of crevices that can cause loss of material due to crevice corrosion.

Management of Loss of Heat Exchanger Performance due to Fouling

The RHR Heat Exchanger Augmented Inspection and Testing Program provides for the following combination of inspections and tests as applicable to manage loss of thermal performance due to fouling.

- Visual inspections are performed at scheduled intervals of the internal surfaces of the Heat Exchanger Channel and Shell sides. These inspections are performed in accordance with the Plant Service Water and RHR Service Water Inspection Program.
- Eddy Current tests are performed at scheduled interval.

The *Suppression Pool Chemistry Control* provides for low limits on halogen content and conductivity and, thereby controls corrosion product build up in the shell side.

The *Plant Service Water and RHR Service Water Chemistry Control* provides for addition of biocides in order to control microbiological and macrobiological species to avoid fouling.

The Structural Monitoring Program, by preventing build up of foreign material in the intake structure, prevents macroorganisms or silt to be carried to heat exchanger components, and thereby, prevents fouling.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 revealed one significant event for RHR Heat Exchangers. During 1996, a sample taken from a RHRSW drain valve contained the presence of nuclides. A root cause investigation and subsequent helium leak test and eddy current testing performed on the 1E11-B001 RHR heat exchanger identified possible leakage in 9 heat exchanger tubes. Subsequent inspection of the tube bundle revealed that, other than the leaking tubes, the tube bundle was in good condition and suitable for continued service. Dents were noted at the tube to tube support connections and may be indicative of tube vibration. However, no exact cause for the tube leakage was identified. No tube leaks for other RHR heat exchangers occurred during the five-year period under consideration.

Table C.2.2.11-1 Aging Management Program Assessment Cracking due to SCC and IGA of Stainless Steel Components With RHR Heat Exchangers

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The RHR Heat Exchanger Augmented Inspection and Testing Program, Suppression Pool Chemistry Control, and Inservice Inspection Program govern aging management for the RHR heat exchangers.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The scheduled inspections required by the RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program are sufficient to detect cracking within stainless steel heat exchanger components prior to loss of intended function.
5. Monitoring and trending for timely corrective actions.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program provide for trending of degradation within RHR heat exchangers.
6. Acceptance criteria are included.	The Suppression Pool Chemistry Control, RHR Heat Exchanger Augmented Inspection and Testing Program, ISI Program provide specific acceptance criteria related to cracking of stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, RHR Heat Exchanger Augmented Inspection and Testing Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a process for identifying deficient conditions and ensuring proper corrective action is taken.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.11-2 Aging Management Program Assessment Cracking Within RHR Heat Exchangers due to Vibration Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program govern aging management for the RHR heat exchangers.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program inspections are designed to provide timely detection of degradation of RHR heat exchangers.
5. Monitoring and trending for timely corrective actions.	The ISI Program and RHR Heat Exchanger Augmented Inspection and Testing Program provide for monitoring and trending of RHR heat exchanger conditions. The Corrective Actions Program provides for monitoring and trending of deficiencies.
6. Acceptance criteria are included.	The ISI Program and RHR Heat Exchanger Augmented Inspection and Testing Program provide detailed acceptance criteria related to cracking within RHR heat exchangers.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, RHR Heat Exchanger Augmented Inspection and Testing Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.11-3 Aging Management Program Assessment Loss of Material Within RHR Heat Exchangers

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, Structural Monitoring Program, RHR Heat Exchanger Augmented Inspection and Testing Program, and ISI Program encompass aging management for the RHR heat exchangers.
2. Preventive actions to mitigate or prevent aging degradation.	The Suppression Pool Chemistry Control and PSW and RHRSW Chemistry Control provides for chemical monitoring and additions designed to mitigate loss of material within the RHR heat exchangers. The Structural Monitoring Program minimizes loss of material by reducing fouling rates
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, the Inservice Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program inspections are designed to provide timely detection of degradation of RHR heat exchangers.
5. Monitoring and trending for timely corrective actions.	The ISI Program, RHR Heat Exchanger Augmented Inspection and Testing Program, and Structural Monitoring Program provide for monitoring and trending of RHR heat exchanger condition.
6. Acceptance criteria are included.	The Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, ISI Program, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program provide detailed acceptance criteria related to loss of material within RHR heat exchangers.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, ISI Program, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a process for identifying deficient conditions and ensuring proper corrective action is taken.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.11-4 Aging Management Program Assessment Loss of Heat Exchanger Performance Within RHR Heat Exchangers

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program govern aging management within RHR heat exchangers.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control and PSW and RHRSW Chemistry Control provides for chemical monitoring and additions designed to minimize fouling within the RHR heat exchangers. The Structural Monitoring Program minimizes particulate intrusion into the heat exchanger components, and thereby reduces fouling rates.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RHR Heat Exchanger Augmented Inspection and Testing Program is designed to provide timely detection of degradation of RHR heat exchangers thermal performance.
5. Monitoring and trending for timely corrective actions.	The RHR Heat Exchanger Augmented Inspection and Testing Program and the Structural Monitoring Program provide for monitoring and trending of data concerning RHR heat exchanger condition.
6. Acceptance criteria are included.	The Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program provide detailed acceptance criteria related to loss of performance within RHR heat exchangers.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, RHR Heat Exchanger Augmented Inspection and Testing Program, PSW and RHRSW Chemistry Control, Suppression Pool Chemistry Control, and Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3 AGING MANAGEMENT REVIEWS FOR FIRE PROTECTION SYSTEM COMPONENTS

The demonstration of aging management for fire protection system components is presented based on the component function within the fire protection system.

- Water Based Fire Suppression Systems
- Fire Protection Diesel Fuel Oil Supply System
- Compressed Gas Based Fire Suppression Systems
- Fire Barriers for Preventing Fire Propagation

Aging management for fire protection systems is accomplished by *Fire Protection Activities*, the *Protective Coatings Program*, and *Diesel Fuel Oil Testing* as described in Appendix A of the LRA.

C.2.3.1 Evaluation of Water Based Fire Suppression Systems

Water based fire suppression systems contain both air (for those dry pipe system components downstream of the multimatic isolation valve) and well water drawn from deep draft wells on site and passed through mechanical filters. See the well water description for more information. The system consists of many general component types.

Components are fabricated from stainless steels, carbon steels, galvanized steels, ceramics copper alloys, cast irons, aluminum alloys, and lead alloys.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.4.1 and C.1.2.6.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, microbiologically influenced corrosion (MIC), selective leaching, and fouling.
- *Cracking* (C.1.2.4.2 and C.1.2.6.2) due to SCC, IGA, and thermal fatigue.
- *Flow Blockage* (C.1.2.4.3) due to fouling.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Aging Effects Requiring Management

Fire Protection Activities provide for aging management of water based fire suppression system components. Fire Protection Activities require flushing of the header loop on a regular basis to remove corrosion product buildup and ensure adequate flow through the system. The diesel fire pumps are visually inspected and operationally tested on a regular schedule. The fire water storage tank internal surfaces are periodically inspected. Sprinkler nozzles are visually inspected and air flow tested on a regular schedule. Valves are cycled to verify functionality. These tests, inspections, and routine maintenance ensure that water based fire suppression system components are able to maintain their intended functions throughout the period of extended operation.

The *Protective Coatings Program* provides for prevention of corrosion within the fire water storage tank by maintaining sufficient coating on the internal surfaces of the storage tank. Results of Fire Protection Activities inspections on the tank are utilized to identify coating reapplication requirements.

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written on fire protection system components. Deficiencies included leaking piping (mostly within buried sections), deterioration of coatings within the fire water storage tank, and fouling of lines due to corrosion product buildup. All of these deficiencies were identified during testing and inspection required by the Fire Protection Activities or during normal walkdown activities. Due to the design features of the system, including excess capacity and loop design, none of these failures was judged to constitute a loss of intended function.

Table C.2.3.1-1 Aging Management Program Assessment, Aging Effects Requiring Management for Water Based Fire Suppression System Components

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Fire Protection Activities and Protective Coatings Program govern aging management for water based fire suppression system components.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program provides for mitigation of corrosion within the fire water storage tank. The Fire Protection Activities prevent or mitigate loss of material by utilizing system flushes to remove undesirable material from the system. Inspection and testing of water based fire suppression systems conducted in accordance with the Fire Protection Activities is sufficient to detect degradation prior to any loss of intended function.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide for timely inspections and performance testing of water based fire suppression system components. The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provides for proper corrective actions any time degradation of water based fire suppression system component is detected. The Protective Coatings Program ensures resolution of deficiencies in a timely manner.
6. Acceptance criteria are included.	The Fire Protection Activities and the Protective Coatings Program provide specific acceptance criteria related to degradation of water based fire suppression system components and coatings.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Fire Protection Activities, and the Protective Coatings Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.2 Evaluation of Fire Protection Diesel Fuel Oil Supply System

Fuel oil supply to the fire protection system diesel driven fire pumps includes the fuel oil storage tank, piping, valves, and strainer baskets.

Components are fabricated from stainless steels, carbon steels, copper alloys, and cast irons.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- Loss of material (C.1.2.5.1 and C.1.2.6.1) due to general corrosion, galvanic corrosion, pitting, crevice corrosion, and MIC.
- Cracking (C.1.2.5.2 and C.1.2.6.2) due to thermal fatigue, SCC, and IGA.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Diesel Fuel Oil Testing* (A.1.3)
- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Aging Effects Requiring Management

Diesel Fuel Oil Testing provides for sampling and analysis of fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to assure that no significant buildup of contaminants exists. If excessive contamination does occur, the program provides for draining and cleaning of the tank as required to reestablish and maintain acceptable contaminant levels. Acceptance criteria for fuels oil quality is established by applicable ASTM standards. See Appendix A.1.3.

Fire Protection Activities provide for visual inspections and performance testing of the fire protection diesel fuel oil supply system. These inspections and tests are conducted on a regular basis and are adequate to detect degradation of system components prior to loss of intended function. Regular performance testing prevents degradation of fuel oil within the supply lines connecting the storage tank and diesel engine.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on fire protection diesel fuel oil system components. These deficiencies related to excessive sedimentation and water within the fire pump diesel fuel oil storage tanks. These deficiencies and subsequent corrective actions were detected and managed by *Diesel Fuel Oil Testing*.

Information Notice 91-46 indicates that several plants have experienced clogging of strainers with sediment and degraded fuel oil. The *Diesel Fuel Oil Testing* and *Fire Protection Activities* provide management of this concern at Plant Hatch as described above.

Table C.2.3.2-1 Aging Management Program Assessment, Aging Effects Requiring Management for Fire Protection Diesel Fuel Oil Supply System Components

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Diesel Fuel Oil Testing and Fire Protection Activities govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Diesel Fuel Oil Testing is designed to mitigate age-related degradation of fire protection diesel fuel oil supply system components by detecting and preventing the introduction of contaminated oil into plant systems.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Fire Protection Activities provides for visual inspections and performance testing of fire protection diesel fuel oil system components.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide a means for evaluating the effectiveness of current diesel fuel oil testing standards in preventing aging degradation within fire protection diesel fuel oil supply system components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	The Fire Protection Activities provide for compilation of data concerning aging of fire protection diesel fuel oil system components.
6.	Acceptance criteria are included.	Diesel Fuel Oil Testing provides detailed acceptance criteria related to aging of fire protection diesel fuel oil system components. The Fire Protection Activities provides acceptance criteria for visual inspections and/or performance testing of fire protection diesel fuel oil system components.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Diesel Fuel Oil Testing, and Fire Protection Activities ensures corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.3 Evaluation of Compressed Gas Based Fire Suppression Systems

Compressed gas fire suppression systems consist of CO_2 and halon-based systems. High-pressure bottles and refrigerated liquid CO_2 storage tanks are used as compressed gas supplies. Components upstream of the pressure isolation valve are exposed to dry compressed gases or refrigerated liquefied gases under normal conditions. Components downstream of the isolation valve are exposed to humid air under normal conditions. Components include valves, piping, nozzles, and storage tanks. See C.1.2.6 for a description of gas environments.

Components are fabricated from carbon steels, galvanized steels, copper alloys, aluminum alloys, cast irons and insulating materials such as polystyrene foam, urethane foam, and isocyanurate.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.6.1) due to general corrosion, galvanic corrosion, selective leaching, pitting, crevice corrosion, wear, and intrusion of water born agents.
- *Cracking* (C.1.2.6.2) due to IGA, SCC, and thermal fatigue.
- *Change in Material Properties* (C.1.2.11.3) due to compaction and settling, intrusion of water borne agents, thermal effects, and material separation within insulating materials.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Aging Effects Requiring Management for Metallic and Insulation Components

Fire Protection Activities provide for visual inspections and performance testing of compressed gas fire suppression systems. These inspections and tests are conducted on a regular basis and are adequate to detect degradation of compressed gas fire suppression system components prior to loss of intended function.

Fire Protection Activities also manage aging of insulation products by providing regular, focused inspections of insulation installed on the CO_2 storage tanks. These inspections are adequate to detect degradation of tank insulation prior to a loss of intended function.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on compressed gas systems. All of these deficiencies related to exterior corrosion of piping components in areas of coating degradation. External components aging effects and associated aging management programs are addressed in section C.2.4 of the LRA. No deficiencies related to aging of component internals or insulation were identified.

Table C.2.3.3-1 Aging Management Program Assessment, Aging Effects Requiring Management for Compressed Gas Fire Suppression System Components

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Fire Protection Activities govern aging management of compressed gas fire suppression system components on a periodic basis.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degredation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Fire Protection Activities provides for specific inspections and performance testing of compressed gas fire suppression systems.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provides for timely inspections and performance testing of compressed gas fire suppression system components.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provides for proper corrective actions any time degradation of a compressed gas fire suppression system component is detected. The Corrective Actions Program ensures resolution of deficiencies in a timely manner.
6. Acceptance criteria are included.	The Fire Protection Activities provides specific acceptance criteria related to degradation of compressed gas fire suppression system components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and the Fire Protection Activities ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.4 Evaluation of Fire Barriers for Preventing Fire Propagation

C.2.3.4.1 Fire Penetration Seals

Fire penetration seals are assemblies fabricated from combinations of the following materials:

- Carbon steel
- Concrete
- Silicon rubber foam
- Fiber material (fiberglass and rockwool)
- Ceramics (ceraboard)

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.11.1 and C.1.4.1) due to general corrosion, crevice corrosion, and pitting of carbon steel sleeves and wear or fretting of fiber and ceramic materials.
- *Change in Material Properties* (C.1.2.11.3 and C.1.4.2) within concrete due to elevated temperature degradation, compaction and settling, and deformation and material separation of fiber, ceramic, and foam materials.
- *Cracking* (C.1.2.11.2 and C.1.4.1) of carbon steel sleeves due to fatigue, and of fiber, ceramic, and foam materials due to thermal degradation.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Degradation of Fire Penetration Seals

Fire Protection Activities provide for visual inspections of fire penetration seals. These inspections occur at regular intervals and are adequate to detect degradation of fire penetration seals prior to any loss of intended function.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on fire penetration seals. These deficiencies were screened to determine which ones might be potentially age-related. All of the failures involved only minor degradation of the seal. None of these failures was determined to be significant since no loss of intended function occurred.

Table C.2.3.4-1 Aging Management Program Assessment, Aging Effects Requiring Management for Fire Penetration Seals

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Fire Protection Activities govern aging management for fire penetration seals.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide for timely inspections of fire penetration seals.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provide for proper corrective actions any time degradation of a fire penetration seal is detected.
6. Acceptance criteria are included.	The Fire Protection Activities provide specific acceptance criteria related to degradation of fire penetration seals.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Fire Protection Activities ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.4.2 Cable Tray Fire Barriers

Cable tray fire barriers consist of Kaowool insulation (or an equivalent material) wrapped around safe shutdown required cable trays and the galvanized steel straps and fasteners used to affix the insulation to the trays.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.11.1) due to general corrosion and galvanic corrosion of galvanized steel fastening components and wear or fretting of insulation.
- *Change in Material Properties* (C.1.2.11.3) of insulation materials due to compaction and settling and thermal degradation.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Degradation of Fire Protection Insulation

Fire Protection Activities provide for visual inspections of fire protection insulation materials installed on cable trays. These inspections occur at regular intervals and are adequate to detect degradation of fire penetration seals prior to any loss of intended function.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that no deficiencies were determined to be age-related.

Generic Letter 92-08, “Thermo-Lag Fire Barriers,” was issued by the NRC in December 1992 when it was discovered that Thermo-Lag 330-1 fire barrier material did not meet NRC requirements as evidenced by failure of the material to pass fire exposure tests. In response, Southern Nuclear indicated that Thermo-Lag would not be relied upon as a fire barrier material at Plant Hatch.

Table C.2.3.4-2 Aging Management Program Assessment, Aging Effects Requiring Management for Cable Tray Fire Barriers

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific structure, component or commodity for the identified aging effect.	The Fire Protection Activities govern aging management for cable tray fire barrier materials on a periodic basis.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular structure, component or commodity intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide for timely inspections of cable tray fire barrier materials.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provide for proper corrective actions any time degradation of a fire penetration seal is detected.
6. Acceptance criteria are included.	The Fire Protection Activities provide specific acceptance criteria related to degradation of cable tray fire barrier materials.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Fire Protection Activities ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.4.3 Fire Doors

Fire doors are metal assemblies fabricated with nonmetallic insulating internals:

Systems:

X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management:

- *Loss of Material* (C.1.2.8.1 and C.1.2.9.1) due to general corrosion of carbon steel structural materials and associated bolts and fasteners.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Applicable Aging Management Programs:

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

Management of Loss of Material due to General Corrosion

Fire Protection Activities provide for visual inspections of fire doors. These inspections occur at regular intervals and are adequate to detect corrosion of fire doors prior to any loss of fire barrier function.

Review of Operating Experience:

A review of the condition reporting database mentioned in section 3.0 showed that approximately 1100 deficiencies had been written on the in-scope fire doors. These deficiencies were screened to determine which ones might be potentially age related. These deficiencies primarily involved problems with active components (e.g., door knobs, closers, etc.) due to mechanical use. No deficiencies resulted from identified age related degradation of the fire doors.

Table C.2.3.4-3 Aging Management Program Assessment for Fire Doors: Loss of Material due to General Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity (SCC) for the identified aging effect.	The Fire Protection Activities include fire rated doors in the Category I buildings, and the Category II Turbine building, Radwaste building west wall, and Fire Pump House.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular SCC function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities require regular inspection and surveillance of fire doors to detect possible degradation and prevent a loss of fire barrier function.
5. Monitoring and trending is included for timely corrective actions.	The Fire Protection Activities provide for routine fire door surveillance to detect degradation and assure timely corrective or mitigative actions to prevent a loss of fire rating.
6. Acceptance criteria are included.	The Fire Protection Activities include acceptance criteria for fire doors against which corrective action is evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and Fire Protection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent recurrence of detrimental effects.

C.2.4 AGING MANAGEMENT REVIEWS FOR MECHANICAL COMPONENT EXTERNAL SURFACES

Component external surfaces may be exposed to three general environment types:

- Inside (C.1.2.8)
- Outside (C.1.2.9)
- Buried or Embedded (C.1.2.10)

See section C.1 or use the above links for external environment definitions.

C.2.4.1 Aging Management Review for Commodity External Surfaces Exposed to an Inside Environment

This evaluation applies to the external surfaces of all inscope mechanical process components located within a controlled building environment at Plant Hatch (reactor building, turbine building, diesel generator building, control building, and intake structure). Components are fabricated from stainless steel, carbon steel, copper alloys (bronze, brass, pure copper), galvanized steel, and cast iron. This section applies only to the normal inside environment where minimal wetting and wet/dry cycling is expected to occur. See section C.1.2.8 for a discussion of the aging effects that may result for the materials in these environments.

Systems

Many systems within the scope of license renewal have systems, structures, or components located within the inside environment. The aging management review for external aging effects is not system dependent.

Aging Effects Requiring Management

- Loss of material (C.1.2.8) due to general corrosion in areas where the external surface is less than 200 °F.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Protective Coatings Program* (A.2.3)
- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Occurring on the Exterior Surfaces of In Scope Components

The *Protective Coatings Program* provides a means for preventing or mitigating loss of material that would otherwise result from contact of the base metal with the environment. Additionally, this program provides instructions on surface cleaning and preparation of component surfaces (specific acceptance criteria is provided for each type of cleaning method including hand cleaning, solvent cleaning, and near white blasting), mixing and thinning of paints, paint application, and inspection and testing of coatings (acceptance criteria is based on the paint manufacturer's recommendations for dry film thickness and a visual examination).

The *Fire Protection Activities* provide for regular walkdowns of fire suppression systems, thereby providing a method for identifying and correcting significant degradation of component surfaces or coatings.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written that related to component exteriors. These deficiencies related to corrosion of carbon steel and low alloy components in areas where the existing coating had broken down, no coating was originally applied, or wetting due to packing leakage had occurred. No aging effects were found that had not been previously identified.

Table C.2.4.1-1 Aging Management Program Assessment, External Surfaces of Inside Commodities: Loss of Material due to Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program and Fire Protection Activities govern aging management the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program and Fire Protection Activities provide for periodic inspections designed to detect degradation of component exterior surfaces.
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program and Fire Protection Activities provide trending of data to ensure proper corrective actions.
6. Acceptance criteria are included.	The Protective Coatings Program and Fire Protection Activities include acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Protective Coatings Program, and Fire Protection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.2 Aging Management Review for Commodity External Surfaces exposed to an Outside Environment

This evaluation applies to the external surfaces of all inscope mechanical process components not located within a controlled building environment at Plant Hatch (excluding buried components). Components are fabricated from stainless steel, carbon steel, copper alloys (bronze, brass, pure copper), galvanized steel, aluminum alloy, and cast iron. See section C.1.2.9 for a discussion of the aging effects that may result for the materials in these environments.

Systems

Many systems within the scope of license renewal have systems, structures, or components located in an outside environment. The aging management review for external aging effects is not system dependent.

Aging Effects Requiring Management

- *Loss of material* (C.1.2.9) due to general corrosion, selective leaching, pitting, crevice corrosion, and galvanic corrosion in areas where the external surface is less than 200 °F and the potential for significant wetting or pooling of water exists.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Protective Coatings Program* (A.2.3)
- *Fire Protection Activities* (A.2.1)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Occurring on the Exterior Surfaces of In Scope Components

The *Protective Coatings Program* provides a means for preventing or mitigating loss of material that would otherwise result from contact of the base metal with the environment. Additionally, this program provides instructions on surface cleaning and preparation of component surfaces (specific acceptance criteria is provided for each type of cleaning method including hand cleaning, solvent cleaning, and near white blasting), mixing and thinning of paints, paint application, and inspection and testing of coatings (acceptance criteria is based on the paint manufacturer's recommendations for dry film thickness and a visual examination).

The *Fire Protection Activities* provide for regular walkdowns of fire suppression systems, thereby providing a method for identifying and correcting significant degradation of component surfaces or coatings.

The *Passive Component Inspection Activities* will require southern Nuclear to inspect the normally in accessible surfaces of in-scope components such as externally located ductwork (X41, Z41) located on the roof of the reactor building, diesel generator building and intake structure during maintenance activities

The *Gas Systems Component Inspections* one-time inspection will include a representative sample of the surfaces to demonstrate the lack of detrimental aging effects.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written that related to component exteriors. These deficiencies related to corrosion of carbon steel and low alloy components in areas where the existing coating had broken down, no coating was originally applied, or wetting due to packing leakage had occurred. No aging effects were found that had not been previously identified.

Table C.2.4.2-1 Aging Management Program Assessment, External Surfaces of Outside Commodities: Loss of Material due to Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program, Gas Systems Component Inspections, Passive Component Inspection Activities, and Fire Protection Activities govern aging management the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing; the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections; the Passive Components Inspection Activities provide for visual or surface inspections; and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program, Passive Component Inspection Activities, Gas Systems Component Inspections, and Fire Protection Activities provide for periodic inspections designed to detect degradation of component exterior surfaces.
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program, Passive Component Inspection Activities, and Fire Protection Activities provide trending of data to ensure proper corrective actions.
6. Acceptance criteria are included.	The Protective Coatings Program, Gas Systems Component Inspection, Passive Component Inspection Activities, and Fire Protection Activities include acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Protective Coatings Program, Gas Systems Component Inspection, Passive Component Inspection Activities, and Fire Protection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.3 Aging Management Review for Commodity External Surfaces exposed to a Buried or Embedded Environment

This evaluation applies to the external surfaces of all inscope mechanical process components that are buried or embedded. Buried and embedded components are fabricated from the following materials: stainless steel, carbon steel, and copper.

Systems

- E11 – Residual Heat Removal (2.3.3.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P41 – Plant Service Water (2.3.4.7)
- T46 – Standby Gas Treatment (2.3.3.6)
- Y52 – Fuel Oil Supply (2.3.4.19)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.10.1) due to general corrosion, galvanic corrosion, selective leaching, pitting, crevice corrosion, and microbiologically influenced corrosion (MIC).

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Passive Component Inspection Activities* (A.3.5)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Inservice Inspection Program* (A.1.9)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Occurring on the Exterior surfaces of Buried In Scope Components

The *Protective Coatings Program* provides a method to ensure protective coatings are correctly applied. Underground piping is covered with a protective coating that is expected to greatly reduce the rates of corrosion occurring on the external surfaces of buried piping. Plant service water, residual heat removal service water, standby gas treatment, HPCI, RCIC, and diesel fuel supply piping were coated with enamel and wrapped with a fiber wrap saturated in coal tar in accordance with AWWA C203-66 when buried. These coatings are expected to prevent corrosion except in those small areas where the coating is breached due to wear.

The *Fire Protection Activities* provides for regular operation and performance testing of fire suppression systems, including water based suppression systems, compressed gas based suppression systems, and fire pump diesel fuel oil supply system. Loss of performance or inventory due to significant leakage of underground piping could be detected by this program.

The *PSW and RHRSW Inspection Program* includes provisions for cleaning, priming, coating, and wrapping underground pipelines within the P41 and E11 systems whenever underground sections of pipe are uncovered. Pipelines are wrapped with coal tar enamel wrapping.

The *Passive Component Inspection Activities* serves to validate the adequacy of the piping coatings in mitigating loss of material by performing inspections of component surfaces anytime an applicable component is unearthed for repair. This information is carefully evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

For PSW and RHRSW piping, the *ISI Program* performs leakage tests that determine the rate of pressure loss or change in flow between the ends of buried piping such that leakage can be determined.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written that related to component exteriors for buried piping segments. Failures of buried components due to corrosion in areas where gaps in the existing coating have occurred during the life of the plant. No failures have been identified where the coating had been properly installed. However, there is some concern over the continued viability of the coating over the extended life of the plant. Programs have been added to address that concern.

Table C.2.4.3-1 Aging Management Program Assessment, External Surfaces of Buried Commodities: Loss of Material due to Corrosion

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, ISI Program, Passive Component Inspection Activities, and Protective Coatings Program include the commodities under consideration in this evaluation.
2.	Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program provides for coating of underground piping to mitigate or prevent corrosion.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections; the Passive Components Inspection Activities provide for visual or surface inspections; the Protective Coatings Program provides for visual inspections; and the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and PSW and RHRSW Inspection Program provide for inspection of buried component surfaces whenever they become accessible. The ISI Program provides tests that detect aging degradation.
5.	Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program, Passive Component Inspection Activities, and ISI Program provide trending of data to ensure proper corrective actions.
6.	Acceptance criteria are included.	The PSW and RHRSW Inspection Program, Passive Component Inspection Activities, ISI Program, and Protective Coatings Program include acceptance criteria against which corrective action will be evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, PSW and RHRSW Inspection Program, Passive Component Inspection Activities, ISI Program, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.4 Evaluation of Plant Insulation Commodities

This commodity group includes insulation and associated jacketing for in-scope components installed on ECCS, plant service water and RHR service water system components.

Thermal insulation serves to maintain design calculation limits, provided freeze protection, and prevent overheating of ECCS diagonals and HPCI pump rooms. The metallic jackets and fasteners serve to protect the insulation from environmental attack and fix the insulation in place.

C.2.4.4.1 Aging Management Review for Insulation

This commodity group includes insulation, L36 (2.3.4.3), installed on inscope ECCS, plant service water and RHR service water system components.

Systems

Insulation evaluated is installed on the following systems:

- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.11.1) due to wear and intrusion of water borne agents.
- *Cracking* (C.1.2.11.2) due to thermal effects and intrusion of water borne agents.
- *Change in Material Properties* (C.1.2.11.3) due to compaction and settling, material separation, intrusion of water and water-borne agents, and thermal effects.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Equipment and Piping Insulation Monitoring Program* (A.2.4)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material, Cracking, and Change in Material Properties

No reasonable method is available to mitigate potential deterioration of insulation at Plant Hatch. However, it is expected that deterioration of insulation at Plant Hatch will occur slowly and would be adequately managed by a focused inspection program. The *Equipment and Piping Insulation Monitoring Program* meets this requirement by providing periodic visual inspections of insulation components.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the L36 system. These deficiencies were screened to determine which ones might be potentially age-related. Several deficiencies were related to damaged, torn, or missing insulation. These areas were localized, generally attributed to mechanical damage, and not deemed to significantly impact thermal performance of the insulated system. Only one record that related to generally deteriorated insulation was discovered. This deterioration was confined to a small area and was not determined to significantly affect the thermal performance of the insulated system.

Table C.2.4.4-1 Aging Management Program Assessment, Insulation: Deterioration of Insulation due to Loss of Material, Cracking, and Change in Material Properties

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Equipment and Piping Insulation Monitoring Program governs aging management for the components under consideration in this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Equipment and Piping Insulation Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Equipment and Piping Insulation Monitoring Program provides timely tests/inspections for detecting degradation.
5. Monitoring and trending for timely corrective actions.	The Equipment and Piping Insulation Monitoring Program provides for timely corrective actions upon discovery of unacceptable conditions.
6. Acceptance criteria are included.	The Equipment and Piping Insulation Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Equipment and Piping Insulation Monitoring Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.4.2 Aging Management Review for Insulation Jacketing

This commodity group includes metal jacketing and fasteners for insulation installed on Class 2 and 3 components. The in-scope insulation jacketing components are installed on ECCS, plant service water and RHR service water system components. Jackets and fasteners are fabricated from stainless steel, galvanized steel and aluminum alloys. These components are part of the L36 system (2.3.4.3).

Systems

Insulation jacketing is installed on the following systems:

- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.8 and C.1.2.9) due to general corrosion, galvanic corrosion; pitting, crevice corrosion, and MIC.
- *Cracking* (C.1.2.8 and C.1.2.9) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Equipment and Piping Insulation Monitoring Program* (A.2.4)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material, Cracking within insulation Metallic Jacketing Materials

No reasonable method is available to mitigate potential deterioration of insulation at Plant Hatch. However, it is expected that deterioration of insulation at Plant Hatch will occur slowly and would be adequately managed by a focused inspection program. The *Equipment and*

Piping Insulation Monitoring Program meets this requirement by providing regular, focused inspections of insulation components.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the L36 system. These deficiencies were screened to determine which ones might be potentially age-related. Several deficiencies were related to damaged, torn, or missing jacketing. These areas were localized, generally attributed to mechanical damage, and not deemed to significantly impact thermal performance of the insulated system.

Table C.2.4.4-2 Aging Management Program Assessment, Insulation Jacketing: Deterioration of Insulation Jacketing due to Loss of Material and Cracking

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Equipment and Piping Insulation Monitoring Program governs aging management for the components under consideration in this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Equipment and Piping Insulation Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Equipment and Piping Insulation Monitoring Program provides timely tests/inspections for detecting degradation.
5. Monitoring and trending for timely corrective actions.	The Equipment and Piping Insulation Monitoring Program provides for timely corrective actions upon discovery of unacceptable conditions.
6. Acceptance criteria are included.	The Equipment and Piping Insulation Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Equipment and Piping Insulation Monitoring Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.5 AGING MANAGEMENT REVIEWS FOR ELECTRICAL DISCIPLINE COMMODITIES

C.2.5.1 Aging Management Review for Phase Bussing

This commodity group includes phase bussing with an internal environment of "Self Heating" and an external environment of "Inside" (excluding containment). The commodity is associated with the bus between 4160/600 volt station auxiliary transformer CD and 600V buses C and D.

Systems

- S11 – Power Transformers (2.5.13)

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that approximately 122 deficiencies had been written on the S11 system. These deficiencies were conservatively screened to determine which ones might be potentially age-related. No age-related failures of the in-scope phase bussing components were found.

C.2.5.2 Aging Management Review for Nelson Frames

This commodity group includes Nelson Electric Multi-Cable Transit Frames (Nelson Frame) located in the walls and floors of the reactor building with an external environment of "Inside" (excluding containment). Some are located in the wall between the reactor building and turbine building. Some are located in the wall between the reactor building and control building. Others are located between floors of the reactor building. Floor mounted frames are mounted on concrete pedestals. Reactor building electrical penetrations allow cables to penetrate the secondary containment boundary and maintain secondary containment leakage rates within design limits.

Systems

- T54 – Reactor Building Penetrations (2.4.7)

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that no deficiencies had been written on the T54 system. No age-related failures of the in-scope Nelson Frame components were found.

C.2.5.3 Aging Management Review for Electrical Splices, Connectors, and Terminal Blocks

This commodity group includes electrical splices, connectors, and terminal blocks with an external environment of “inside” or “outside.” The commodities are located throughout the plant, in the drywell, and in outdoor pits.

Systems

Plant-wide.

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that numerous deficiencies had been written on electrical splices, connectors, and terminal blocks. These deficiencies were conservatively screened to determine which ones might be potentially age-related. Twenty-four failures were found which could potentially be age-related. After further review, all of the failures were dismissed as either being event driven, involving EQ components, or involving equipment which is not in scope.

C.2.5.4 Aging Management Review for Insulated Electrical Cable Outside Containment

This commodity group includes insulated electrical cable located at Plant Hatch with an external environment of “Inside” and “Outside.” Some cables could be exposed to submergence. This evaluation includes low and medium voltage cable and I & C cable.

Systems

Plant-wide.

Aging Effects Requiring Management

- Change in Insulation Resistance (C.1.3) due to water treeing or water intrusion in submerged cables only.

Comparing the elevations of the conduits in the pull boxes with the pull box water levels, it was determined that conduits containing safety-related circuits are exposed to moisture for some period of time between pull box inspections. This is detrimental to the insulated cable in the duct runs.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Wetted Cable Activity* (A.1.16).

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

The outdoor pull boxes are checked for water level quarterly and drained if necessary.

Megger testing is performed on the feeder cable back to the switchgear for RHRSW and PSW pump motors along with the leads from the surge pack to the motor.

Megger testing is performed on the feeder cables back to the switchgear for core spray and RHR pump motors along with the leads to the motor. Megger testing is not performed on transformer feeder cables.

Megger testing provides evidence of gross cable insulation deficiencies. Corrective actions are taken if megger readings are unacceptable.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that approximately 753 deficiencies had been written on electrical cable. These results were obtained in two ways. First, a review of the deficiencies for all systems was performed in order to obtain all that pertained to cable. Then, a printout of the deficiency database was run using keyword “cable.” Both processes yielded virtually the same results. These deficiencies were conservatively screened to determine which ones might be potentially age-related. Twenty-eight cable failures were found which could potentially be age-related. After further review, all of the failures were dismissed as either being event driven, involving EQ components, involving wiring in complex active assemblies, or involving equipment which is not in scope.

Davis-Besse experienced the failure of a 5 kV power cable on October 2, 1999. The failed cable had a neoprene jacket and was run partially underground in PVC conduit. Neoprene is one of the least tolerant jacket materials with respect to moisture absorption. Neoprene jacketed cables are not used in outdoor duct runs at Plant Hatch.

Table C.2.5.4-1 Aging Management Program Assessment, Change in Insulation Resistance Due to Water Immersion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Wetted Cable Activity governs aging management for the component within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Wetted Cable Activity requires quarterly draining of pull boxes if sufficient amounts of water are detected.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Wetted Cable Activities provide for visual inspections or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Wetted Cable Activity specifies that the method of detection of cable insulation damage is by megger testing. The frequency of performance is based on repetitive task intervals.
5. Monitoring and trending are included for timely corrective actions.	The Wetted Cable Activity monitors and trends data to ensure the proper performance of the associated system equipment.
6. Acceptance criteria are included.	The Wetted Cable Activity provides detailed acceptance criteria related to pull box water levels and megger testing.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Wetted Cable Activity ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and are adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.5.5 Aging Management Review for Insulated Electrical Cable – Containment

This commodity group includes instrumentation and control cable for the neutron monitoring system, and installed communication equipment, with an external environment of "inside." These cables are located in the drywell. Radiation detectors are replaced on a neutronics depletion schedule. Part of the cable is replaced with the detector. The cable that is replaced goes from the detector to a junction box outside the subpile room. The cable being addressed in this AMR summary is the portion from the subpile room junction boxes to the electrical penetration assemblies.

Systems

- C71 – Reactor Protection System (2.5.4) (C51 – neutron monitoring system cables only)
- R51 – Installed Communication Equipment (2.5.12)

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that approximately 753 deficiencies had been written on electrical cable. These results were obtained in two ways. First, a review of the deficiencies for all systems was performed in order to obtain all that pertained to cable. Then, a printout of the deficiency database was run using keyword "cable." Both processes yielded virtually the same results. These deficiencies were conservatively screened to determine which ones might be potentially age-related. Twenty-eight cable failures were found which could potentially be age-related. After further review, all of the failures were dismissed as either being event driven, involving EQ components, involving wiring in complex active assemblies, or involving equipment which is not in scope.

C.2.6 AGING MANAGEMENT REVIEWS FOR CIVIL DISCIPLINE COMMODITIES

C.2.6.1 Aging Management Review for Concrete Structures

This commodity group includes concrete components (i.e., walls, beams, slabs, columns, floors, roof, underground duct runs and pull boxes, foundations including those for equipment) and masonry block walls in several Class 1 structures listed below.

Systems

- T23 – Primary Containment (2.4.3)
- T24 – Fuel Storage (2.4.4)

- T29 – Reactor Building (2.4.5)
- U29 – Turbine Building (2.4.8)
- W35 – Intake Structure (2.4.9)
- Y29 – Yard Structures (2.4.10)
- Y32 – Main Stack (2.4.11)
- Y39 – Diesel Generator Building (2.4.12)
- Z29 – Control Building (2.4.13)

Aging Effects Requiring Management

- *Loss of Material* (C.1.4.2) Cracking and Spalling due to corrosion of embedded steel
- *Cracking* (C.1.4.2) in masonry block walls (applicable to reactor and control buildings, and main stack only)

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Protective Coatings Program* (A.2.3)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material, Cracking, and Spalling due to Corrosion of Embedded Steel, and Cracking in Masonry Block Walls

The *Structural Monitoring Program* (SMP) inspection process assesses the ongoing overall conditions of the listed structures, and identifies any ongoing degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

The *Protective Coatings Program* provides for the prevention and mitigation for corrosion of embedded steel at the surface of the concrete.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified three concrete related deficiencies; one each was written on the T23, T29, and W35 functions. These deficiencies were screened to determine which ones might be potentially age related. No age-related deficiencies or failures of the in-scope T23, T24, T29, U29, W35, Y29, Y32, Y39, and Z29 components were found.

The ground water chemistry has been reviewed since the late 1960's for pH, chloride, and sulfate concentrations. No known conditions exist which would modify the ground water chemistry from that which has existed since the plant was constructed. Also, based on a discussion with personnel of Watershed Planning and Monitoring Program branch of the Georgia Environmental Protection Division, it is unlikely that pH, sulfates, and chlorides in the water of the Altamaha River would change appreciably. The more recent information indicates values that are considered well within acceptable limits to prevent aggressive chemical attack on concrete structures. The temperature range and atmospheric pollution are within the ranges used in the original design and construction of the plant.

In 1996 and 1997, an initial evaluation was performed, as part of the Structural Monitoring Program, to establish a "base-line" condition of the subject buildings and structures. Areas within the scope of the Maintenance Rule were visually inspected and photographs were made to document notable degrees of degradation. Specific items and areas included in the inspections were the roof, settlement around the building, outer concrete walls and penetrations, interior concrete columns, beams, floors, walls, interior steel superstructure columns, girders and beams, foundations, anchor bolts, and equipment slabs. Specific items and areas also included in the inspection of the sealants were the outer precast concrete wall panels and the CST transfer pump wall joints. All inspected areas were found "Acceptable-no further evaluation required." Condition surveys were conducted in April 1997 and November 1997. The inspection reports concluded the same findings as previous reports. Previous results of settlement surveys, and associated calculations, were also reviewed and all structures were found to be within acceptable settlement limits.

NRC I&E Bulletin No. 80-11 identified several masonry block walls that needed to be investigated for possible inadequate structural strength. SNC identified such walls and provided modifications to meet the requirements of this bulletin. Plant Hatch found no age-related degradation in the masonry block walls. The NRC concluded that Hatch had appropriately complied with requirements of the Bulletin and no further work was required beyond normal inspections and evaluations which were committed to in response to the Bulletin. NRC also revisited Plant Hatch several years later and assured themselves of proper maintenance of the block walls per the requirements of I&E Bulletin 80-11.

Table C.2.6.1-1 Aging Management Program Assessment, Concrete Structures: Loss of Material, Cracking and Spalling due to Corrosion of Embedded Steel in Concrete

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program, under the Maintenance Rule, includes the concrete components within the scope of aging management review. The Protective Coatings Program includes the embedded steel at the surface of the concrete.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program provides preventive actions that mitigate or prevent corrosion of embedded steel at the concrete surface.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	The aging effects requiring management for the concrete components in Class I structures and the turbine building are readily detectable by visual inspection. The Structural Monitoring Program performs visual inspections, which are evaluated to determine the structural impact of any degradation noted.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program inspects the Class 1 structures on a 5-cycle schedule, except for the Intake Structure and the Condenser Bay in the Turbine Building which are inspected during every cycle.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and evaluation to assure timely, corrective, or mitigative actions. The SMP records the results for evaluation purposes, and attempts to rectify them before the next inspection.
6. Acceptance criteria are included	The Structural Monitoring Program and Protective Coatings Program include acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structural Monitoring Program and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with Structural Monitoring Program inspections.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.6.1-2 Aging Management Program Assessment, Concrete Structures: Cracking in Masonry Block Walls in Reactor and Control Buildings, and in Main Stack

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program, under the Maintenance Rule, includes the masonry block walls located in the Reactor and Control Buildings and in the Main Stack.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	The aging effects requiring management for the masonry block walls identified in item 1 above are readily detectable by visual inspection. The Structural Monitoring Program performs visual inspections, which are evaluated to determine the structural impact of any degradation noted.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program inspects the Reactor and Control Buildings and the Main Stack on a 5-cycle schedule.
5.	Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and evaluation to assure timely, corrective or mitigative actions. The Structural Monitoring Program records the results for evaluation purposes, and attempts to rectify them before the next inspection.
6.	Acceptance criteria are included	The Structural Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with Structural Monitoring Program inspections.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.2 Aging Management Review for Steel Primary Containment and Internals

This commodity group includes steel commodities for primary containment, primary containment penetrations, and containment internal structures. The materials of construction for the drywell shell, torus, penetrations and internal structures consist of a variety of carbon steels and stainless steels. Carbon steels are galvanized or coated with an inorganic zinc primer and epoxy topcoat.

Systems

- T23 – Primary Containment (2.4.3)
- T52 – Drywell Penetrations (2.4.6)

Aging Effects Requiring Management

- Loss of Material (C.1.4.1) due to general corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.4.1) due to fatigue of the torus.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Primary Containment Leak Rate Testing Program* (A.1.14)
- *Component Cyclic or Transient Limit Program* (A.1.12)
- *Protective Coatings Program* (A.2.3)
- *Suppression Pool Chemistry Control* (A.1.7)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and MIC

Primary Containment Leak Rate Testing procedures provide for the scheduled periodic testing of the primary containment pressure boundary and pressure boundary penetrations to detect degradation of the pressure boundary. Inspections are conducted in accordance with 10 CFR 50, Appendix J.

The *Protective Coatings Program* provides for periodic inspection of structural component surfaces, including fasteners and associated service level I coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The *ISI Program* provides for visual inspections of internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. Inspections are conducted in accordance with ASME Section XI Table IWE-2500-1.

Suppression Pool Chemistry Control limits detrimental impurities and conductivity within the suppression pool and thereby mitigates aging. Suppression Pool Chemistry Control implements the EPRI guidance on BWR water chemistry for auxiliary systems.

The *Passive Component Inspection Activities* serve to validate the adequacy of the drywell floor and equipment sump discharge piping sections to perform a primary containment function by performing inspections, similar to VT-1, of component internal surfaces anytime an applicable component is opened for periodic maintenance or repair. This information is evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

Management of Cracking due to Fatigue of the Torus

The *Component Cyclic or Transient Limit Program* is designed to track cyclic and transient occurrences, including the limiting location for the torus, to ensure that reactor coolant pressure boundary components will remain within the ASME Code Section III limits.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that approximately 62 deficiencies had been written on the T23 and T52 systems. These deficiencies were screened to determine which ones might be potentially age-related. Ten of the deficiencies resulted from age-related degradation of the in-scope components due to minor corrosion. There were no component functional failures. These deficiencies were discovered during required visual inspections and pressure testing. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.6.2-1 Aging Management Program Assessment, Steel Commodities for Primary Containment and Internals: Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and Microbiologically Influenced Corrosion (MIC)

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program, Protective Coatings Program, Primary Containment Leak Rate Testing Program, Passive Component Inspection Activities, and Suppression Pool Chemistry Control, include visual inspections and testing of primary containment and specifically includes corrosion as a monitored aging effect.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements. Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections, the Passive Components Inspection Activities provide for visual or surface inspections, the Primary Containment Leakage Rate Testing Program provides for visual inspections and performance testing, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program, Passive Component Inspection Activities, and Protective Coatings Program require visual inspections of the primary containment and internals on a regular scheduled basis. Leak rate testing is also performed on a regular scheduled basis via the Primary Containment Leakage Rate Testing Program.
5. Monitoring and trending is included for timely corrective actions.	The ISI Program, Protective Coatings Program, Primary Containment Leakage Rate Testing Program, and Passive Component Inspection Activities require the monitoring of degradation and utilize the Corrective Action Program to implement timely corrective action.
6. Acceptance criteria are included	The ISI Program, Protective Coatings Program, Primary Containment Leakage Rate Testing Program, Passive Component Inspection Activities, and Suppression Pool Chemistry Control establish acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, ISI Program, Protective Coatings Program, Primary Containment Leakage Rate Testing Program, Passive Component Inspection Activities, and Suppression Pool Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent recurrence of detrimental effects.

Table C.2.6.2-2 Aging Management Program Assessment, Steel Commodities for Primary Containment and Internals: Cracking Due to Fatigue of the Torus

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity (SCC) for the identified aging effect.	The Component Cyclic or Transient Limit Program tracks the SRV discharges to the torus and provides specific limitations and acceptance criteria related to the CUF of the torus.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program is designed to prevent unacceptable fatigue leading to cracking of the torus.
3. Parameters monitored or inspected are linked to the degradation of the particular SCC intended function.	The Component Cyclic or Transient Limit Program monitors the CUF of the torus. The CUF is directly linked to prevention of cracking due to fatigue. The program provides specific acceptance criteria related to a CUF<1.0 for the torus.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Component Cyclic or Transient Limit Program provides for monitoring of the torus CUF once per operating cycle.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program monitors and trends torus CUF data to ensure that a CUF<1.0 is maintained at all times.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program provides, via monitoring of the CUF of the torus, detailed acceptance criteria to prevent fatigue cracking of the torus.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Component Cyclic or Transient Limit Program provides for tracking of the torus CUF and the Corrective Actions Program provides a method for tracking and resolving deficiencies.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities in order to prevent future occurrences.

C.2.6.3 Aging Management Review for Steel Structures in Seismic Category I Buildings, the Turbine Building and Category I Yard Structures

This commodity group includes steel and nonferrous commodities for Seismic Category I buildings and structures and select Category II buildings and structures important to the safety of Category I structures. This includes the reactor buildings, control building, river intake structure, diesel generator building, main stack, condensate storage tank foundations and containment walls, liquid nitrogen storage tank foundations, service water valve boxes, turbine building, Fire protection pump house foundation, and an exterior portion of the radwaste buildings. The materials of construction consist of carbon steels, stainless steels, and copper alloy. Carbon steels are coated with an inorganic zinc primer and epoxy topcoat or galvanizing.

Systems

- F15 – Refueling Equipment (2.3.4.2)
- L48 – Access Doors (2.3.4.4)
- T24 – Fuel Storage (2.4.4)
- T29 – Reactor Building (2.4.5)
- T31 – Cranes, Hoists, and ElevatorsSec2.pdf (2.3.4.13)
- T38 – Tornado Vents System (2.3.4.14)
- T54 – Reactor Building Penetrations (2.4.7)
- U29 – Turbine Building (2.4.8)
- W33 – Traveling Water Screens/Trash Racks System (2.3.4.16)
- W35 – Intake Structure (2.4.9)
- Y29 – Yard Structures (2.4.10)
- Y32 – Main Stack (2.4.11)
- Y39 – Diesel Generator Building (2.4.12)
- Z29 – Control Building (2.4.13)

Aging Effects Requiring Management

- *Loss of Material* (C.1.4.1) due to general corrosion, crevice corrosion, pitting and microbiologically influenced corrosion (MIC) of carbon steel and of submerged stainless steel components.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Structural Monitoring Program* (A.2.5)
- *Protective Coatings Program* (A.2.3)
- *Overhead Crane and Refueling Platform Inspections* (A.1.10)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and MIC

The *Structural Monitoring Program* provides for the visual inspection of structural components on a scheduled basis. The SMP will inspect structural components for loss of material due to general corrosion.

The *Protective Coatings Program* provides for inspection of structural component surfaces, including fasteners. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The *Overhead and Refueling Platform Crane Inspection Program* provides for the visual inspection and testing of the reactor building overhead cranes and crane rail supports, and refueling platform to assure safe operation of the cranes.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that approximately 40 deficiencies had been written on the systems listed above. These deficiencies were screened to determine which ones might be potentially age-related. Four of the deficiencies resulted from age-related degradation due to corrosion of the in-scope components. There were no component functional failures. These deficiencies were discovered during visual inspections and routine surveillances. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

In 1996 and 1997, an initial evaluation was performed, as part of the Structural Monitoring Program, to establish a “base-line” condition of the subject buildings and structures. Areas within the scope of the Maintenance Rule were visually inspected and photographs were made to document notable degrees of degradation. Specific items and areas included in the inspections were penetrations steel, interior steel superstructure columns, girders and beams, anchor bolts, and embedded steel in walls, floors, and equipment slabs. Also included in the inspections were structural steel and miscellaneous steel, bolts, and anchors located outside in the applicable structures in the scope of the Structural Monitoring Program. All inspected areas were found “Acceptable- no further evaluation required.” Condition surveys were conducted in April 1997 and November 1997. The inspection reports concluded the same findings as previous reports. Previous results of settlement surveys, and associated calculations, were also reviewed and all structures were found to be within acceptable settlement limits.

Table C.2.6.3-1 Aging Management Program Assessment for Steel Structures, Loss of Material Due to General Corrosion

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program and Protective Coatings Program includes all of the Class 1 buildings and the Turbine building and specifically includes corrosion as a monitored aging effect. The Overhead Crane and Refueling Platform Inspections require frequent inspection of load bearing steel components for corrosion.
2.	Preventive actions to mitigate or prevent aging degradation.	Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections, the Overhead Crane and Refueling Platform Inspection provides for visual inspections or performance testing, and the Protective Coatings Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the Turbine building on a regular scheduled basis based on historical performance. Overhead Crane and Refueling Platform Inspections require frequent visual inspections. The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5.	Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions. The SMP requires inspection of the subject buildings and structures on a regular scheduled basis. The Protective Coatings Program provides for monitoring and trending of deficiencies.
6.	Acceptance criteria are included	The Structural Monitoring Program, Overhead Crane and Refueling Platform Inspections, and Protective Coatings Program include acceptance criteria against which corrective actions related to corrosion are evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structural Monitoring Program, Overhead Crane and Refueling Platform Inspections, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent the recurrence of detrimental effects.

Table C.2.6.3-2 Aging Management Program Assessment for Steel Structures, Loss of Material Due to Crevice Corrosion, Pitting, and Microbiologically Influenced Corrosion (MIC)

	Attributes	Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program and Protective Coatings Program includes all of the Class 1 buildings and the Turbine building and specifically includes corrosion as a monitored aging effect.
2.	Preventive actions to mitigate or prevent aging degradation.	Protective Coatings Program provides preventive actions that mitigate or prevent loss of material due to corrosion by maintaining the applied surface coatings.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections, and the Protective Coatings Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the Turbine building on a regular scheduled basis based on historical performance The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5.	Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions. The SMP requires inspection of the subject buildings and structures on a regular scheduled basis. The Protective Coatings Program provides for monitoring and trending of deficiencies.
6.	Acceptance criteria are included	The Structural Monitoring Program and Protective Coatings Program include acceptance criteria against which corrective actions related to corrosion are evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structural Monitoring Program, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent the recurrence of detrimental effects.

C.2.6.4 Aging Management Review for Component Supports

This commodity group includes steel and aluminum commodities for select Seismic Category I and Seismic Category II/I components and component supports. This includes:

- Supports for piping, ducts and tubing
- Cable trays, conduits and supports for cable trays and conduits
- Electrical panels and supports
- Instrument racks and supports

The materials of construction consist of a variety of carbon steels, stainless steels and aluminum. Carbon steels are coated with an inorganic zinc primer and epoxy topcoat or galvanizing.

Systems

- H11 – Main Control Room Panels (2.5.8)
- H21 – In-plant Auxiliary Control Panels (2.5.9)
- L35 – Piping Specialties (2.4.1)
- R33 – Conduits, Raceways, and Trays (2.4.2)

Aging Effects Requiring Management

- Loss of Material (C.1.4.1) due to general corrosion, crevice corrosion, pitting and microbiologically influenced corrosion (MIC) of carbon steel and of submerged stainless steel components.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Structural Monitoring Program* (A.2.5)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and MIC

The *Structural Monitoring Program* provides for the visual inspection of component supports on a scheduled basis. The SMP inspects component supports made of carbon steel for loss of material due to general corrosion.

The *Protective Coatings Program* provides for periodic inspection of structural component surfaces, including fasteners. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that approximately 200 deficiencies had been written on the H11, H21, L35, and R33 systems which involved the subject components and supports. These deficiencies were screened to determine which ones might be potentially age-related. Twenty-three deficiencies resulted from age-related degradation of the in-scope components. These deficiencies were discovered during visual inspections and routine surveillances. The deficiencies were due to corrosion of support base plates or other carbon steel component subjected to standing water. There were no component functional failures. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.6.4-1 Aging Management Program Assessment for Component Supports: Loss of Material Due to General Corrosion, Crevice Corrosion, Pitting and Microbiologically Influenced Corrosion (MIC)

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes visual inspections of safety-related and Seismic II/I components and component supports for corrosion. The Protective Coatings Program applies to all structures and components which are susceptible to and experience corrosion.
2. Preventive actions to mitigate or prevent aging degradation.	Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspections of in-scope components and component supports on a regular scheduled basis. The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a regular scheduled basis. The Protective Coatings Program provides for monitoring and trending of deficiencies.
6. Acceptance criteria are included	The Structural Monitoring Program and Protective Coatings Program include acceptance criteria against which corrective action related to corrosion will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, the Structural Monitoring Program, and the Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events. It requires that reasonable actions be taken to enhance programs and activities to prevent recurrence of detrimental effects.

C.2.6.5 Aging Management Review for Spent Fuel Pool Liner, Components, and Racks

This commodity group includes:

- Spent fuel pool liner, plugs, gates, storage racks, bolting, and miscellaneous steel inside the spent fuel pool.

The material of construction is stainless steel. All these components are exposed to an environment of demineralized water.

Systems

- T24 – Fuel Storage (2.4.4)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.2.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC)

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fuel Pool Chemistry Control* (A.1.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to crevice corrosion, pitting, MIC

Fuel Pool Chemistry Control provides for mitigation of loss of material within the fuel pool by limiting detrimental impurities and conductivity. Fuel pool water quality is monitored on a weekly basis and corrective actions are taken in the event that limits are exceeded. Fuel Pool Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that no deficiency was written on the T24 system related to loss of material due to crevice corrosion, pitting, or MIC.

Table C.2.6.5-1 Aging Management Program Assessment, SFP Liner, Components & Racks: Loss of Material due to MIC, Pitting and Crevice Corrosion in the Stainless Steel Liner & Components located in the Spent Fuel Pool and Refueling Canal

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Fuel Pool Chemistry Control governs the components included in this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Fuel Pool Chemistry Control is designed to mitigate and prevent age-related degradation by controlling fluid purity and composition. Also, this program accomplishes timely monitoring and goal setting for degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	Due to chemistry controls, this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	Due to chemistry controls, this attribute of aging management is not required.
5. Monitoring and trending is included for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included	Fuel Pool Chemistry Control provides detailed acceptance criteria to insure proper orientation of the demineralizers within the SFP.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	Fuel Pool Chemistry Control provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies, and includes root cause determination.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with the chemical sampling inspections.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.6 Aging Management Review for Aluminum

This commodity group includes aluminum used at Plant Hatch in various environments as listed below:

- Aluminum countersunk head rivet for fuel/control rod handling in the reactor building
- Aluminum seismic restraints for the fuel storage racks in the spent fuel pool
- Aluminum storage rack components in the new fuel storage vault
- Aluminum cover plates and clip angles in the pull boxes (yard structures)
- Aluminum support frame for tornado relief vents
- Aluminum blowout panels and fasteners in the steam chase walls between the reactor building and turbine building

The aluminum seismic restraints for the fuel storage racks in the spent fuel pool are exposed to an environment of demineralized water. The countersunk head rivet in the fuel/control rod handling platform, storage rack components in the new fuel storage vault and aluminum blowout panels and fasteners in the steam chase are exposed to air. The predominant environment for the pull boxes is outside, which indicates the structures are exposed to normal outside weather conditions. The aluminum support frames for tornado relief vents are exposed to an inside environment as well as an outside environment (atmosphere).

Systems

- F15 – Refueling Equipment (2.3.4.2)
- T24 – Fuel Storage (2.4.4)
- T29 – Reactor Building (2.4.5)
- T38 – Tornado Relief Vents (2.3.4.14)
- Y29 – Yard Structures (2.4.10)
- Z29 – Control Building (2.4.13)

Aging Effects Requiring Management

- Loss of Material (C.1.4.1) due to galvanic corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC), applicable only to the aluminum seismic restraints for the fuel storage racks in the spent fuel pool demineralized water.

This aging effect is applicable to the spent fuel pool seismic restraints.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fuel Pool Chemistry Control* (A.1.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Galvanic corrosion, Crevice Corrosion, Pitting, and MIC

Fuel Pool Chemistry Control provides for mitigation of loss of material within the fuel pool by limiting detrimental impurities and conductivity. Fuel pool water quality is monitored on a weekly basis and corrective actions are taken in the event that limits are exceeded. Fuel Pool Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that no deficiency was written on the F15, T24, T29, T38, Y29, and Z29 systems related to loss of material due to galvanic corrosion, pitting, and MIC.

Table C.2.6.6-1 Aging Management Program Assessment, Aluminum: Loss of Material Due to Galvanic corrosion, MIC, Pitting and Crevice Corrosion of Aluminum components within the Spent Fuel Pool

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Fuel Pool Chemistry Control governs aging management of the Aluminum components within the spent fuel pool.
2. Preventive actions to mitigate or prevent aging degradation.	Fuel Pool Chemistry Control is designed to mitigate and prevent age-related degradation by controlling fluid purity and composition. Also, this program accomplishes timely monitoring and goal setting for degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Due to chemistry controls, this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	Due to chemistry controls, this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included.	Fuel Pool Chemistry Control provides detailed acceptance criteria to insure proper orientation of the demineralizers within the SFP.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	Fuel Pool Chemistry Control provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies, and includes root cause determination.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with the chemical sampling inspections.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.7 Aging Management Review for Structural Sealants

This commodity group includes sealants and seal materials which are utilized in safety-related structures and components, are required for structural integrity of safety-related structures, and perform these functions without moving parts or change in configuration and properties. These sealants are typically not replaced based on qualified life or specified time period and are subject to aging. This includes:

- Joint seal and caulk sealant in the joint between the reactor building exterior precast panels.
- Main control room environmental control system (MCRECS) duct flange gaskets and flex connectors.

Systems

- T29 – Reactor Building (2.4.5)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Material property changes and cracking* (C.1.4.3) due to thermal exposure for reactor building joint seal and caulk sealant and the MCRECS duct flange gaskets and flex connectors.
- *Loss of Adhesion* (C.1.4.3) due to exposure to excessive moisture for reactor building joint seal and caulk sealant.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Passive Component Inspection Activities* (A.3.5)
- *Structural Monitoring Program* (A.2.5)
- *Gas Systems Component Inspections* (A.3.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Adhesion, Material Property Changes, and Cracking

The Structural Monitoring Program provides for the visual inspection of reactor building joint seal and caulk sealant on a scheduled basis.

The *Gas Systems Component Inspections* provides for a one time visual inspection of a representative sample of systems with dry and wetted gas internal environments to provide objective evidence that the aging effects for systems with gases as internal environments are being adequately managed for MCRECS duct flange gaskets and flex connectors.

The *Passive Component Inspection Activities* provides for the detailed visual inspection of internals of selected plant equipment, including HVAC ducts, and the collection, trending, and reporting of aging related degradation for MCRECS duct flange gaskets and flex connectors.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that a relatively small number of deficiencies had been written on sealants important to the function of structures for the systems listed above. These deficiencies were screened to determine which ones might be potentially age-related. There were two deficiencies identified which resulted from age-related degradation of the in-scope components. These deficiencies were due to deterioration of a portion of the sealant (caulk) and backing rod in the joint between the reactor building exterior precast panels. No deficiencies were found to be associated with the control room duct gasket or flex connector material. The deficiencies were discovered during visual inspections and routine surveillances. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.6.7-1 Aging Management Program Assessment, Structural Sealants: Material Property Changes and Cracking due to Thermal Exposure

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes the Class 1 buildings and turbine building and addresses structural integrity. The Passive Component Inspection Activities includes the MCRECS ductwork. The Gas Systems Component Inspections include systems exposed to internal gas environments.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, the Structural Monitoring Program provides for visual inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the turbine building on a regular basis. The Passive Component Inspection Activities and Gas Systems Component Inspections include the MCRECS duct flex connectors and duct flange gaskets.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a scheduled basis. The Passive Component Inspection Activities occurs on a frequency that is consistent with other component inspections.
6. Acceptance criteria are included	The Structural Monitoring Program, Gas Systems Component Inspections, and Passive Component Inspection Activities include acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structuring Monitoring Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides control of plant procedures and records.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent the recurrence of detrimental aging effects.

Table C.2.6.7-2 Aging Management Program Assessment, Structural Sealants: Loss of Adhesion due to Exposure to Excessive Moisture

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes the reactor building exterior precast panel joint seals and caulk sealant.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the turbine building on a regular basis.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a scheduled basis.
6. Acceptance criteria are included	The Structural Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.8 Aging Management Review for Tornado Relief Vent Assemblies

This commodity group includes tornado relief vent assemblies that are utilized in safety-related structures, and are required for containment and structural integrity of safety-related structures. Though these components are considered active assemblies, they are considered in-scope for structural integrity purposes. These vents are typically not replaced based on qualified life or specified time period and are subject to aging. This commodity group includes:

- Acrylic dome

Systems

- T38 – Tornado Vent System (2.3.4.14)

Aging Effects Requiring Management

- *Cracking* (C.1.4.4) due to weathering of acrylic material.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage applicable aging effects are as follows:

- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links. What follows is a demonstration that the applicable aging effects identified will be adequately managed during the period of extended operation.

Demonstration of Aging Management

The *Structural Monitoring Program* provides for periodic visual inspections of the tornado vent assemblies for cracking due to weathering.

Review of Operating Experience

Only one deficiency written on tornado vents important to the intended function was identified as resulting from age-related degradation of the in-scope components. This deficiency was due to cracking of the dome material due to weathering. The deficiency was discovered during visual inspections and routine surveillance. The *Corrective Actions Program* was utilized to correct/repair this deficiency. There was no functional failure of the tornado roof vent system or secondary containment.

The tornado relief vent assemblies have been replaced once to repair degraded domes in December 1993. The vents were replaced on the Control and Turbine building roofs. Additional vent domes were added to the Reactor Building roof on top of existing vent domes.

Table C.2.6.8-1 Aging Management Program Assessment, Tornado Relief Vents: Cracking

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes the tornado vents on the Reactor building.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the reactor building in which the tornado vents are located, on a periodic basis.
5.	Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a scheduled basis.
6.	Acceptance criteria are included	The Structural Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.7 REFERENCES

C.2.7.1 Documents Incorporated by Reference into the Hatch LRA.

1. (BWRVIP-74), “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” Electric Power Research Institute (EPRI) TR-113596, September 1999.
2. (BWRVIP-27), “BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines,” EPRI TR-107286, April 1997.
3. (BWRVIP-38), “BWR Shroud Support Inspection and Flaw Evaluation Guidelines,” EPRI TR-108823, September 1997.
4. (BWRVIP-41), “BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines,” EPRI TR-108728, October 1997.
5. (BWRVIP-48), “Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” EPRI TR-108724, February 1998.
6. (BWRVIP-76), “BWR Core Shroud Inspection and Flaw Evaluation Guidelines,” EPRI TR114232, November 1999.
7. (BWRVIP-18), “BWR Core Spray Internals and Flaw Evaluation Guidelines,” EPRI TR-106740, July 1996.
8. (BWRVIP-26), “BWR Top Guide Inspection and Flaw Evaluation Guidelines,” EPRI TR-107285, December 1996.
9. (BWRVIP-47), “BWR Lower Plenum Inspection and Flaw Evaluation Guidelines,” EPRI TR-108727, December 1997.

C.2.7.2 General References

- (BWRVIP 29), “BWR Water Chemistry Guidelines,” EPRI TR-103515-R1, December 1996.
- EPRI TR-106092 “Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Coolant Systems,” September 1997.
- EPRI NSAC/202-L, "Recommendations for an Effective Flow-Accelerated Corrosion Program."
- EPRI TR-107396, “Closed Cooling Water Chemistry Guidelines,” October 1997.
- EPRI NP-5461, “Component Life Estimation: LWR Structural Materials Degradation Mechanisms,” September 1987.
- ASME Boiler and Pressure Vessel Code, 1989 Edition, July 1989.
- Generic Letter 88-01 “NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,” 1988.
- NRC NUREG 0619 “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking, resolution of Generic Technical Activity A 10,” November 1980.
- Appendix G to Part 50 of Title 10 of the Code of Federal Regulations, “Fracture Toughness Requirements,” December 1995.

- Appendix H to Part 50 of Title 10 of the Code of Federal Regulations, "Reactor Vessel Material Surveillance Program Requirements," December 1995.
- Part 54 of Title 10 of the Code of Federal Regulations, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," May 1995.
- (BWRVIP-01), "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," Revision 2, EPRI TR-107079, October 1996.
- (BWRVIP-07), "Guidelines for Reinspection of BWR Core Shrouds," EPRI TR 105747, February 1996.
- (BWRVIP-63), "BWR Vessel and Internals Program Shroud Vertical Weld Inspection and Evaluation Guidelines," June 1999.
- NRC Generic Letter 91-17 "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," October 1991.
- EPRI NP-5769 "Degradation and Failure of Bolting in Nuclear Power Plants," Vols. 1 and 2, Project 2520-7, 1988.
- NUREG 1339 "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," 1990.
- Generic Letter 89-13 with Supplement 1 "Service Water System Problems Affecting Safety-Related Equipment," 1990.
- AWWA C203 (American Water Works Association) "AWWA Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines - Enamel and Tape – Hot Applied," 1966 Edition.
- Edwin I. Hatch Nuclear Plant Units 1 and 1 Environmental Qualification Central File.
- NRC I. E. Bulletin 80-11 "Masonry Wall Design," May 1980.
- NRC Information Notice 92-20 "Inadequate Local Leak Rate Testing," March 1992.
- NRC Information Notice 91-46 "Degradation of Emergency Diesel Generator Fuel Oil Deliver Systems," July 1991.
- NRC Generic Letter 92-08 "Thermo-Lag 330-1 Fire Barriers," December 1992.

Appendix E

TECHNICAL SPECIFICATION CHANGES

CONTENTS

E.1 PROPOSED CHANGES

E.1.1 DESCRIPTION OF CHANGES

As part of the license renewal application development process for Plant Hatch, Southern Nuclear Operating Company (SNC) proposes to revise the Plant Hatch Unit 1 and Unit 2 Technical Specifications requirements for reactor vessel pressure and temperature (P/T) limits. In evaluating the reactor pressure vessel (for both Hatch 1 and 2) for the license renewal term, the effects of irradiation on the core beltline region have been analyzed to determine the impact of the extended operating period on the pressure-temperature operating limits, as required by 10CFR50, Appendix G.

The evaluation (incorporating Extended Power Uprate at 17 Effective Full Power Years (EFPY)) has been performed for a lifetime of 54 EFPY for both Units. This input was used to generate pressure-temperature curves for 54 EFPY for both Units. In addition, intermediate curves for 36, 40, 44, and 48 EFPY for Unit 1 have been developed, due to the expected irradiation shift for the Hatch 1 vessel.

In support of the proposed changes, General Electric (GE) has prepared and issued GE-NE-B1100827-00-01, "Plant Hatch Units 1 & 2, RPV Pressure Temperature Limits License Renewal Evaluation," which is provided as Enclosure 3.

E.1.2 PROPOSED CHANGES TO FIGURES 3.4.9-1, 3.4.9-2, AND 3.4.9-3 OF HATCH UNIT 1 AND 2 TECHNICAL SPECIFICATIONS

The proposed change replaces the current P-T curves with new curves generated as part of GE's evaluation contained in GE-NE-B1100827-00-01. The evaluation provides for a lifetime of 54 Effective Full Power Years for both Units, which encompasses the 60-year renewed operating license term. In addition, intermediate curves for 36, 40, 44, and 48 EFPY for Unit 1 have been provided, due to the expected irradiation shift for the Hatch 1 vessel. The existing 20 and 24 year curves for RPV inservice hydrostatic and inservice leakage tests are retained for Unit 1.

E.1.3 JUSTIFICATION FOR CHANGES

One of the major considerations for extended life of the reactor pressure vessel is irradiation of the core region, or beltline. The effect of irradiation is to shift the reference nil-ductility transition temperature (RT_{NDT}) of the beltline materials. This shift must be evaluated in order to conform to the requirements of 10 CFR 50, Appendix G. To encompass the effects of irradiation for the license renewal term, a maximum lifetime of 54 EFPY was used to determine the effects of irradiation and to develop the P-T curves.

GE has evaluated the effect of an additional twenty years of operation on the P-T limits in the above referenced report. New curves have been generated, incorporating the effects of the renewal term into the existing curves which already consider the effects of extended power uprate. P-T curves were developed for three reactor conditions: pressure test, non-nuclear heatup and cooldown, and core critical operation. The new curves ensure that vessel P-T limits are not exceeded during all phases of operation for the renewal period. There are no proposed changes to the Limiting Condition for Operation or to any of the surveillances of specification 3.4.9. All the curves were generated based on the approved methodologies of 10 CFR 50 Appendix G.

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Enclosure 1

Edwin I. Hatch Nuclear Plant
Request to Revise Technical Specifications:
Pressure and Temperature Limits

Page Change Instructions

Unit 1

Page	Instruction
3.4-25	Replace
3.4-26	Replace
3.4-27	Replace

Unit 2

Page	Instruction
3.4-25	Replace
3.4-26	Replace
3.4-27	Replace

Enclosure 2

Proposed Changes to Units 1 and 2 Technical Specification
Figures 3.4.9-1, 3.4.9-2, and 3.4.9-3

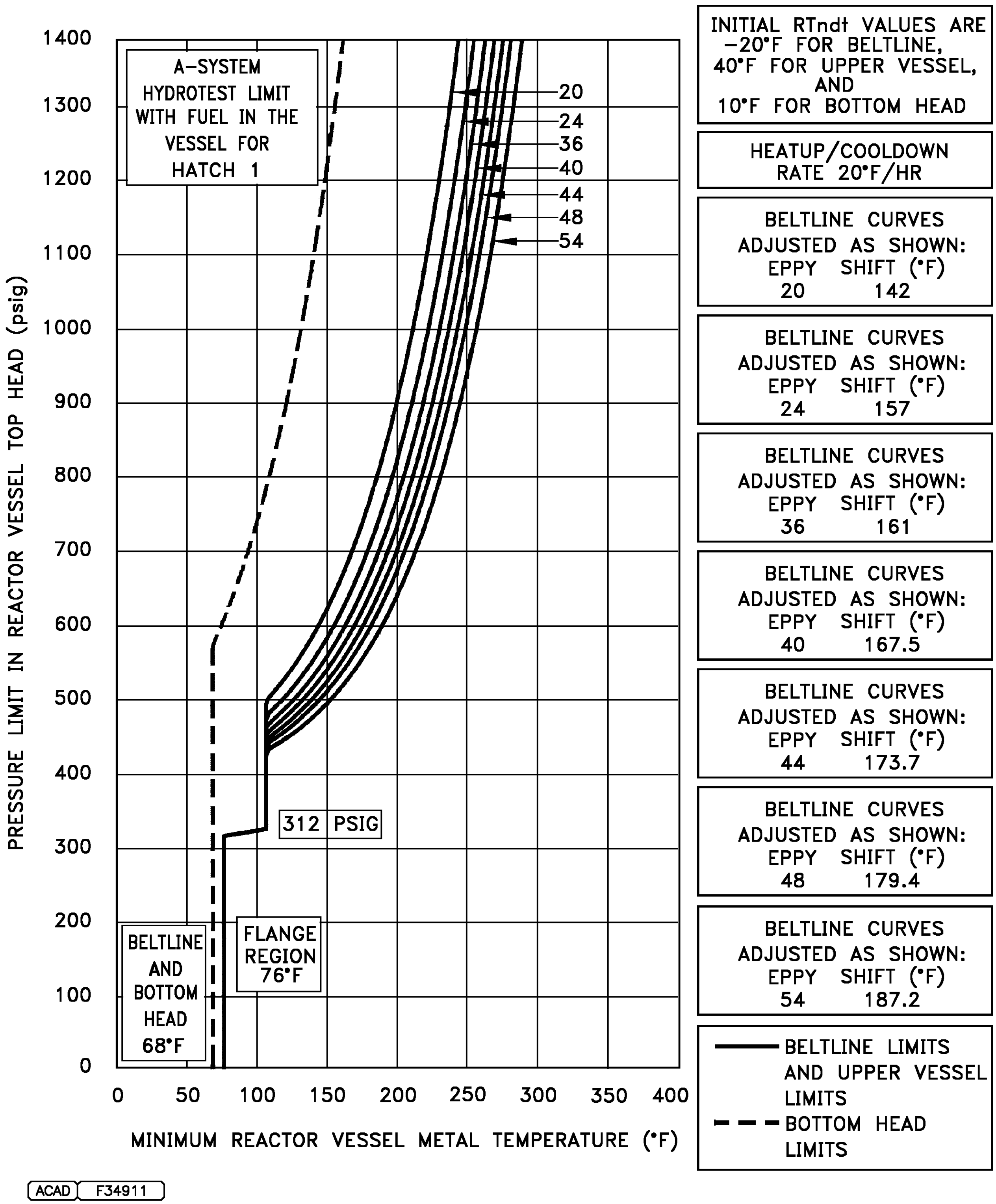
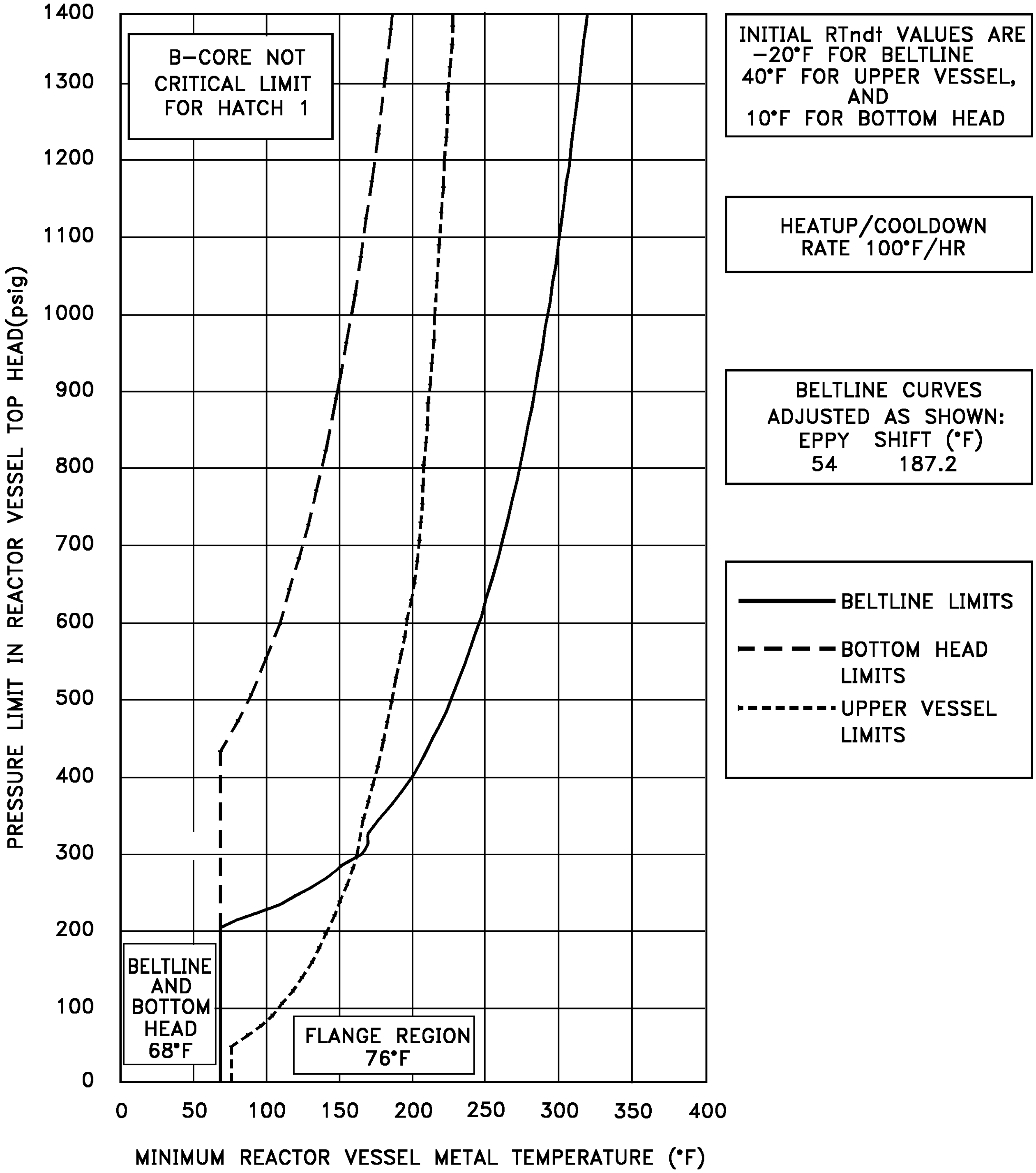


Figure 3.4.9−1 (Page 1 of 1)
Pressure/Temperature Limits for
Inservice Hydrostatic and Inservice Leakage Tests



ACAD F34921

Figure 3.4.9−2 (Page 1 of 1)
Pressure/Temperature Limits for Non−Nuclear Heatup,
Low Power Physics Tests, and Cooldown following a shutdown

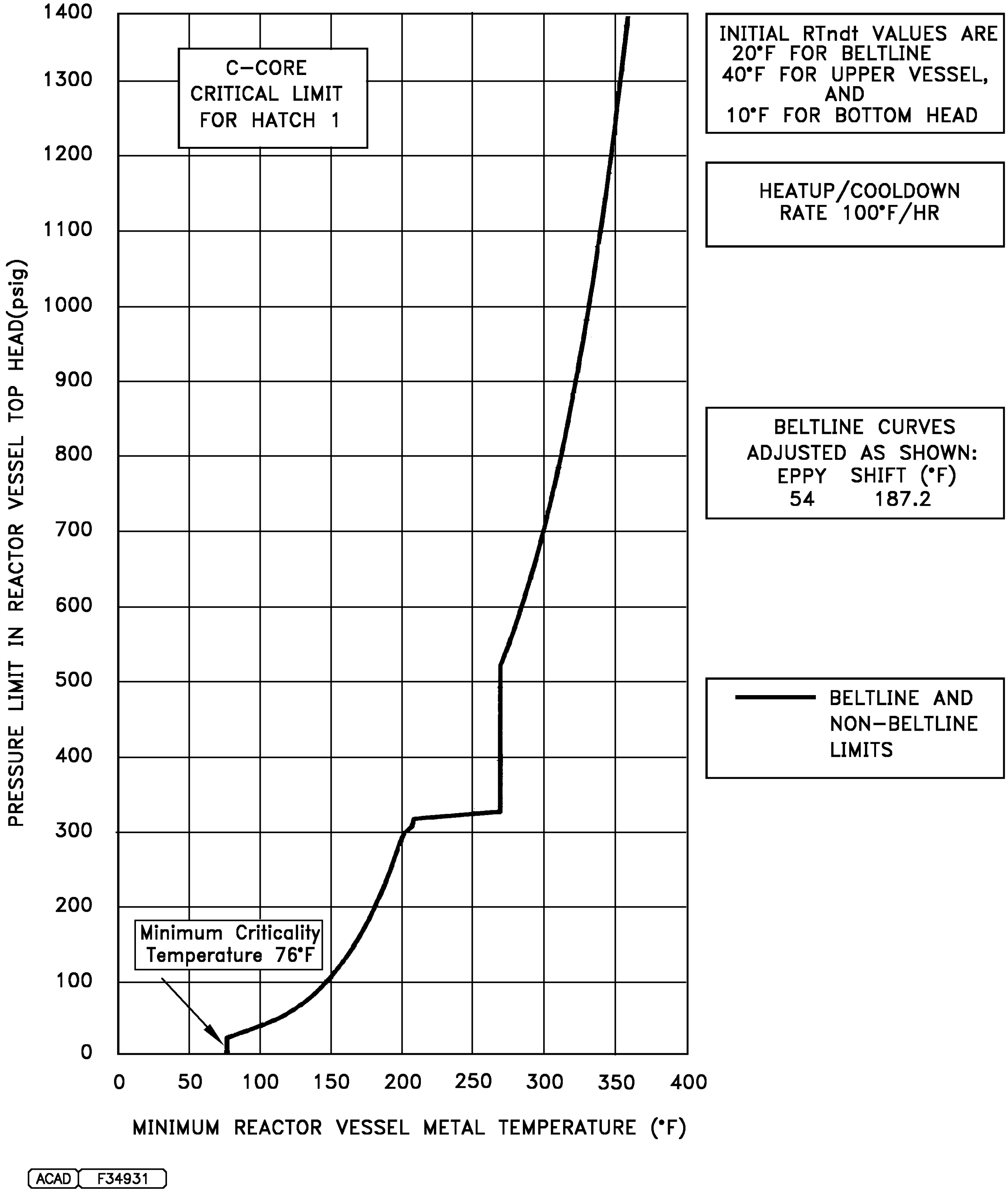


Figure 3.4.9-3 (Page 1 of 1)
Pressure/Temperature Limits for Criticality

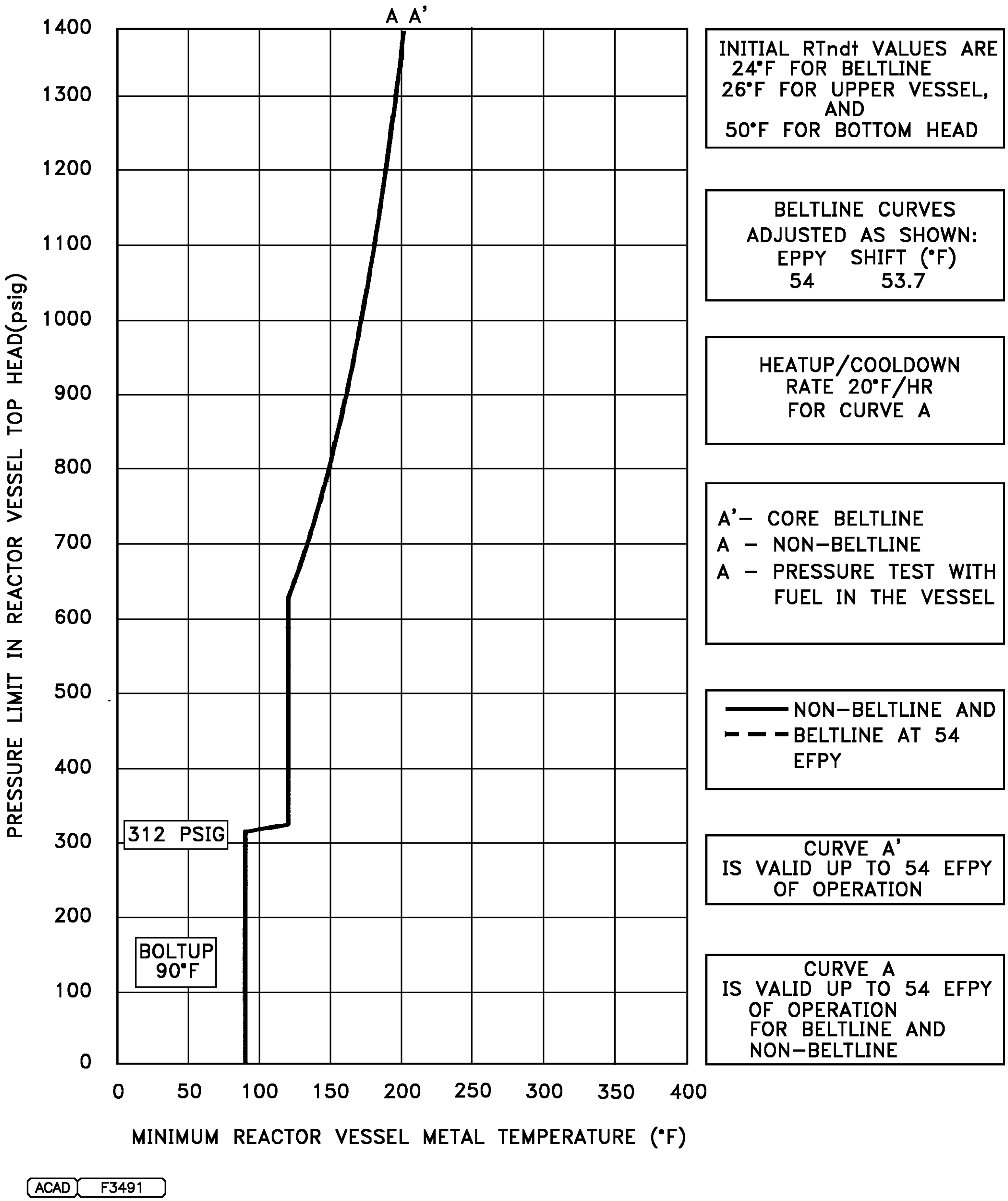


Figure 3.4.9–1 (Page 1 of 1)
Pressure/Temperature Limits for
Inservice Hydrostatic and Inservice Leakage Tests

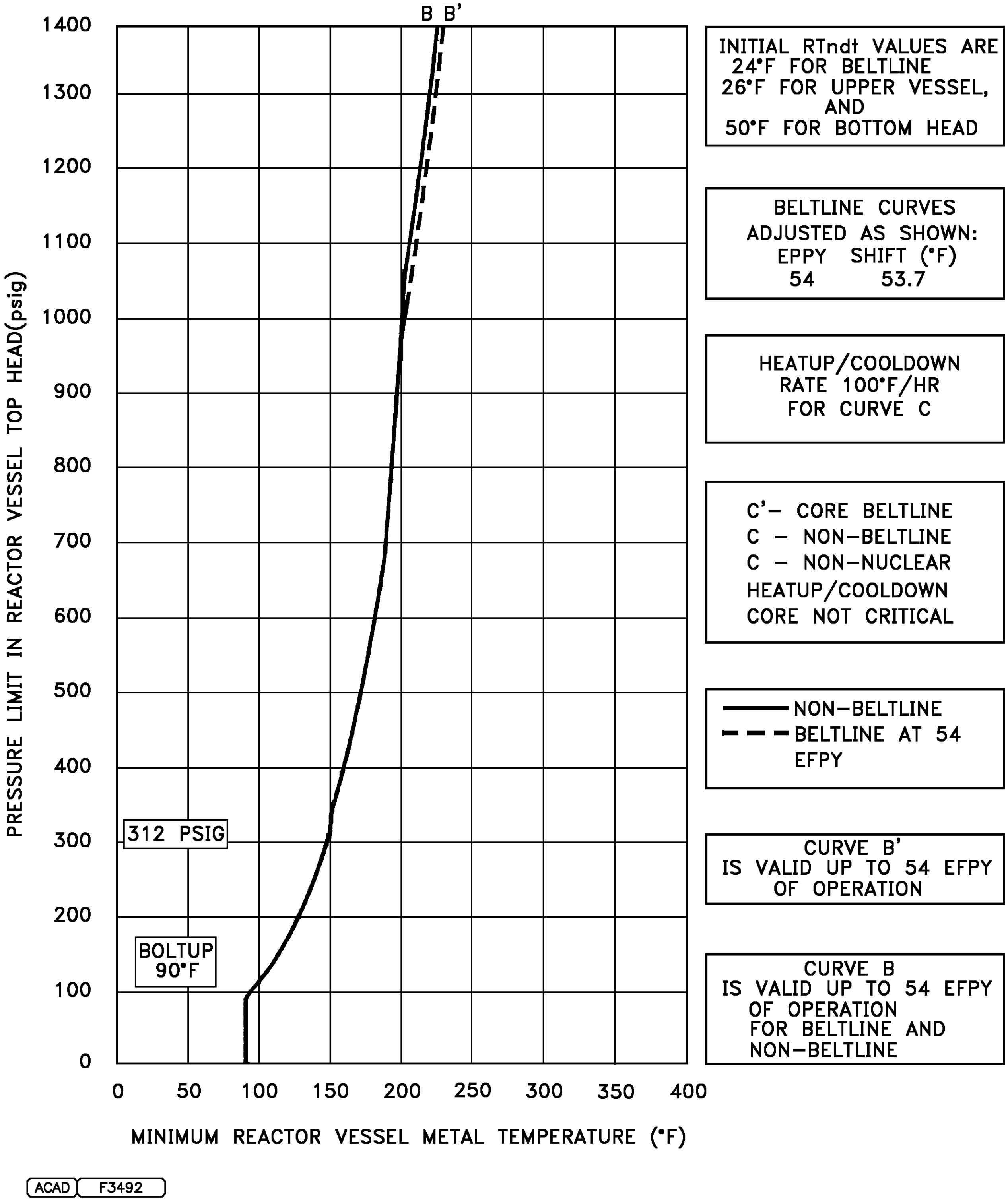


Figure 3.4.9–2 (Page 1 of 1)
Pressure/Temperature Limits for Non–Nuclear Heatup,
Low Power Physics Tests, and Cooldown following a shutdown

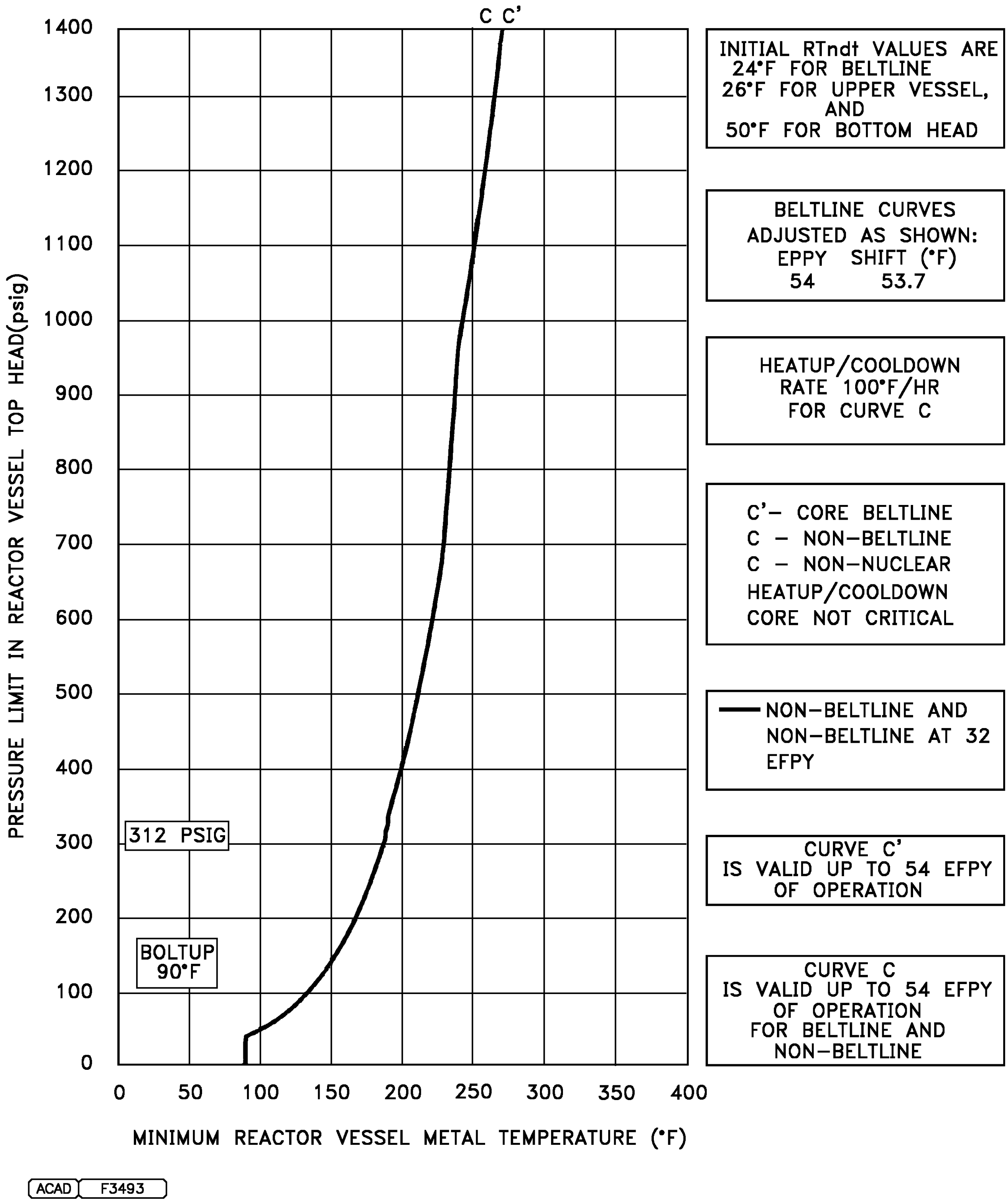


Figure 3.4.9–3 (Page 1 of 1)
Pressure/Temperature Limits for Criticality

Enclosure 3

Plant E. I. Hatch Units 1 and 2

RPV Pressure Temperature Limits
License Renewal Evaluation
GE – NE – B1100827 – 00 – 01

GE Nuclear Energy

Structural Assessment and Mitigation
General Electric Company
175 Curtner Avenue, San Jose, CA 95125

GE-NE-B1100827-00-01
Class II

March 1999

PLANT HATCH UNITS 1 & 2
RPV PRESSURE TEMPERATURE LIMITS
LICENSE RENEWAL EVALUATION

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CONTENTS OF THIS REPORT
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ABSTRACT

As part of the effort to evaluate the reactor pressure vessel (for both Hatch 1 and 2) for the license renewal term, the effects of irradiation on the core beltline region have been evaluated. The purpose of this evaluation was to provide input to the pressure-temperature operating limits, as required by 10CFR50, Appendix G [1].

The evaluation (incorporating Extended Power Uprate at 17 Effective Full Power Years (EFPY) [2]) has been performed for a lifetime of 54 EFPY for both Units. This input was used to generate pressure-temperature curves for 54 EFPY for both Units. In addition, intermediate curves for 36, 40, 44, and 48 EFPY for Unit 1 have been provided, due to the expected irradiation shift for the Hatch 1 vessel.

1. INTRODUCTION

One of the major considerations for extended life of the Reactor Pressure Vessel is irradiation of the core region, or beltline. The effect of irradiation is to shift the reference nil-ductility transition temperature (RT_{NDT}) of the beltline materials. This shift must be evaluated in order to conform to the requirements of 10CFR50, Appendix G [1]. To encompass the effects of irradiation for the license renewal term, a maximum lifetime of 54 EFPY was used to determine the effects of irradiation (see Section 3), and to develop the pressure-temperature (P-T) curves (Section 4).

The (P-T) curves included in this report have been developed to present steam dome pressure versus minimum vessel metal temperature incorporating appropriate non-beltline limits and irradiation embrittlement effects in the beltline. Complete P-T curves were developed for 54 effective full power years (EFPY) for both Hatch 1 and 2; in addition, intermediate P-T curves for Hatch Unit 1 have been included for 36, 40, 44 and 48 EFPY, due to the expected irradiation shift for the Hatch 1 vessel. The methodology used to generate the P-T curves in this report is the same as the methodology used to generate the P-T curves for extended power uprate [2]. The pressure-temperature (P-T) curves are established to the requirements of 10CFR50, Appendix G [1] to assure that brittle fracture of the reactor vessel is prevented. The method used to account for irradiation embrittlement is described in Regulatory Guide 1.99, Revision 2 [3], or Rev 2.

In addition to beltline considerations, there are non-beltline discontinuity limits such as nozzles, penetrations, and flanges which affect the P-T curves. The non-beltline limits are based on generic analyses which are adjusted to the maximum reference temperature of nil ductility transition (RT_{NDT}) for the applicable Hatch 1 or 2 vessel components. The non-beltline limits are also governed by requirements in [1].

Furthermore, curves are included to allow monitoring of the bottom head regions of the vessel separate from the beltline region and upper vessel. This refinement could minimize heating requirements prior to pressure testing.

2. RESULTS AND CONCLUSIONS

Based on the results of the evaluation, the following results and conclusions were determined:

- For Unit 1, the 54 EFPY RPV peak fluence prediction is 3.47×10^{18} n/cm^2 at the vessel wall, based on extended power uprate. The 54 EFPY fluence prediction is 2.51×10^{18} n/cm^2 at 1/4 T. (See Section 3). For Unit 2, the 54 EFPY RPV peak fluence prediction is 3.82×10^{18} n/cm^2 at the vessel wall, based on extended power uprate. The 54 EFPY fluence prediction is 2.77×10^{18} n/cm^2 at 1/4 T. (See Section 3)

- The adjusted reference temperature (ART = Initial RT_{NDT} + ΔRT_{NDT} + Margin) was predicted for each beltline material, based on the methods of Regulatory Guide 1.99, Rev 2. The ART for the limiting material for Unit 1, Plate G-4804-2, Heat C4114-2, at 54 EFPY is 167.2°F. For Unit 2, the limiting ART at 54 EFPY is 77.7°F (Plate G-6603-2, Heat C8553-1). Both plates are lower than the 200°F requirement of 10CFR50 Appendix G [1] and Rev 2 [3].

- An update of the beltline material USE values at 54 EFPY was performed using the Reg. Guide 1.99, Rev. 2 methodology. The Equivalent Margin Analyses demonstrate that the 10CFR50 Appendix G [1] safety requirements are met.

- P-T curves were developed for three reactor conditions: pressure test (Curve A), non-nuclear heatup and cooldown (Curve B), and core critical operation (Curve C) which are valid for up to 54 EFPY of operation. For Unit 1, the beltline curve is more limiting for Curve A at pressures above approximately 410 psig. For Curves B and C, the beltline curves are limiting for pressures above approximately 300 psig. The P-T curves for 54 EFPY are shown in Figures 4-1 through 4-3 [The intermediate curves for 36, 40, 44, and 48 EFPY are located in Appendices A-D]. For Unit 2, the bottom head curve is more limiting for Curve A at pressures above approximately 610 psig. For Curve B, the Feedwater nozzle limits are applicable in the range 90-960 psig. For Curves B and C, the beltline curves are limiting for pressures above approximately 960 psig. The P-T curves for 54 EFPY are shown in Figures 4-4 through 4-6.

3. ADJUSTED REFERENCE TEMPERATURE AND UPPER SHELF ENERGY

The 54 EFPY peak fluence values of 3.47×10^{18} n/cm^2 and 3.82×10^{18} n/cm^2 for Hatch Unit 1 and Hatch Unit 2, respectively, are used to calculate the 54 EFPY 1/4T fluence values of 2.51×10^{18} n/cm^2 and 2.77×10^{18} n/cm^2 (Tables 3-1 and 3-2, for Units 1 and 2, respectively). The 54 EFPY 1/4T fluence is used in this section to calculate adjusted reference temperatures (ARTs) and upper shelf energy (USE) decrease for the beltline materials.

3.1 ADJUSTED REFERENCE TEMPERATURE AT 54 EFPY

The effect on adjusted reference temperature (ART) due to irradiation in the beltline materials is determined according to the methods in Reg. Guide 1.99, Rev. 2 [3], as a function of neutron fluence and the element contents of copper (Cu) and nickel (Ni). The specific relationship from Reg. Guide 1.99, Rev. 2 [3] is:

$$\text{ART} = \text{Initial } RT_{NDT} + \Delta RT_{NDT} + \text{Margin} \quad (3\text{-}1)$$

where:

$$\Delta RT_{NDT} = CF \cdot f^{(0.28-0.10 \log f)} \quad (3\text{-}2)$$

$$\text{Margin} = 2\sqrt{\sigma_I^2 + \sigma_\Delta^2} \quad (3\text{-}3)$$

CF = chemistry factor from Table 1 or Table 2 of Reg. Guide 1.99, Rev. 2 [3]

f = 1/4T fluence (n/cm^2) divided by 10^{19}

σ_I = standard deviation on initial RT_{NDT} which is taken to be 0°F

σ_Δ = standard deviation on ΔRT_{NDT}, 28°F for welds and 17°F for base material, except that σ_Δ need not exceed 0.50 times the ΔRT_{NDT} value

The ART values for 54 EFPY are calculated based upon chemistry data as described in Table 3-1 and 3-2 for Hatch Unit 1 and Hatch Unit 2, respectively.

3.2 ART VS. EFPY

Each beltline plate and weld ΔRT_{NDT} value is determined by multiplying the CF from Reg. Guide 1.99, Rev. 2 [3] determined for the Cu-Ni content of the material, by the fluence factor for the EFPY being evaluated. The Initial RT_{NDT}, ΔRT_{NDT} and Margin are added to get the ART of the material. The 54 EFPY ART values for all of the beltline plates and welds are shown in Tables 3-1 and 3-2. The ART for the limiting beltline material in Hatch Unit 1, plate Heat C4114-2, at 54 EFPY is 167.2°F. The ART for the limiting beltline material in Hatch Unit 2, plate Heat C8553-1, at 54 EFPY is 77.7°F.

3.3 UPPER SHELF ENERGY AT 54 EFPY

Unirradiated Upper Shelf data were not available for all of the material heats. Due to the lack of specific pre-operational USE data, Hatch 1 and 2 have been evaluated to verify that the BWR Owners' Group Equivalent Margin Analyses are applicable. The calculations in Tables 3-3 through 3-6 show that the equivalent margin analyses are applicable. The Equivalent Margin Analyses demonstrate that the 10 CFR 50, Appendix G safety requirements are satisfactorily met for Hatch Units 1 and 2. The Owners' Group Program Report [4] was submitted to the NRC in December 1993 and approved by SER on December 8, 1993.

BELTLINE ART VALUES FOR Hatch 1

Lower-Intermediate
Thickness = 5.38 inches

Lower
Weld Thickness = 5.38 inches (Girth)
Plate Thickness = 6.375 inches (and Long Weld)

Lower-Intermediate
54 EFPY Peak I.D. fluence = 3.47E+18 n/cm^2
54 EFPY Peak 1/4 T fluence = 2.51E+18 n/cm^2

Lower
54 EFPY Peak I.D. fluence = 2.36E+18 n/cm^2
54 EFPY Peak 1/4 T weld fluence = 1.71E+18 n/cm^2
54 EFPY Peak 1/4 T plate fluence = 1.61E+18 n/cm^2

COMPONENT	HEAT OR HEAT/LOT	%Cu	%Ni	CF	Fluence Level n/cm^2	Initial RTndt °F	54 EFPY Δ RTndt °F	σ_I	σ_Δ	Margin °F	54 EFPY Shift °F	54 EFPY ART °F
PLATES:												
Lower												
G-4805-1	C4112-1	0.13	0.64	92	1.61E+18	8	47.7	0.0	17.0	34.0	81.7	89.7
G-4805-2	C4112-2	0.13	0.64	92	1.61E+18	10	47.7	0.0	17.0	34.0	81.7	91.7
G-4805-3	C4149-1	0.14	0.57	99	1.61E+18	-10	51.4	0.0	17.0	34.0	85.4	75.4
Lower-Intmed												
G-4803-7	C4337-1	0.17	0.62	128	2.51E+18	-20	80.0	0.0	17.0	34.0	114.0	94.0
G-4804-1	C3985-2	0.13	0.58	90	2.51E+18	-20	56.3	0.0	17.0	34.0	90.3	70.3
G-4804-2*	C4114-2	0.13	0.70	245	2.51E+18	-20	153.2	0.0	17.0	34.0	187.2	167.2
WELDS:												
Lower Long												
1-307	13253/1092 Flux 3791	0.221	0.732	189	1.61E+18	-50	98.0	0.0	28.0	56.0	154.0	104.0
Lower-Intmed Long.												
1-308	IP2809/1092 Flux 3854	0.22	0.735	189	2.51E+18	-50	118.2	0.0	28.0	56.0	174.2	124.2
1-308	IP2815/1092 Flux 3854	0.316	0.724	219	2.51E+18	-50	136.9	0.0	28.0	56.0	192.9	142.9
Girth												
Lower to Lower-Int Girth												
1-313	90099/0091 Flux 3977	0.197	0.060	91	1.71E+18	-10	48.5	0.0	24.2	48.5	96.9	86.9
1-313	33A277/0091 Flux 3977	0.258	0.165	126	1.71E+18	-50	67.1	0.0	28.0	56.0	123.1	73.1

* CF Adjusted by a factor of 2.62

Table 3-1: Hatch 1 ART Values (54 EFPY)

BELTLINE ART VALUES FOR Hatch 2

Lower-Intermediate
Thickness = 5.38 inches

Lower-Intermediate
54 EFPY Peak I.D. fluence = 3.82E+18 n/cm^2
54 EFPY Peak 1/4 T fluence = 2.77E+18 n/cm^2

Lower
Weld Thickness = 5.38 inches (Girth)
Plate Thickness = 6.375 inches (and Long Weld)

Lower
54 EFPY Peak I.D. fluence = 2.44E+18 n/cm^2
54 EFPY Peak 1/4 T weld fluence = 1.77E+18 n/cm^2
54 EFPY Peak 1/4 T plate fluence = 1.67E+18 n/cm^2

COMPONENT	HEAT OR HEAT/LOT	%Cu	%Ni	CF	Fluence Level n/cm^2	Initial RTndt °F	54 EFPY Δ RTndt °F	σ_I	σ_Δ	Margin °F	54 EFPY Shift °F	54 EFPY ART °F
PLATES:												
Lower												
G-6603-1	C8553-2	0.08	0.58	51	1.67E+18	-20	26.9	0.0	13.4	26.9	53.7	33.7
G-6603-2	C8553-1	0.08	0.58	51	1.67E+18	24	26.9	0.0	13.4	26.9	53.7	77.7
G-6603-3	C8571-1	0.08	0.53	51	1.67E+18	0	26.9	0.0	13.4	26.9	53.7	53.7
Lower-Intmed												
G-6602-2	C8554-1	0.08	0.57	51	2.77E+18	-20	33.1	0.0	16.6	33.1	66.2	46.2
G-6602-1	C8554-2	0.08	0.58	51	2.77E+18	-10	33.1	0.0	16.6	33.1	66.2	56.2
G-6601-4	C8579-2	0.11	0.48	73	2.77E+18	-4	47.4	0.0	17.0	34.0	81.4	77.4
WELDS:												
Lower Long												
101-842	10137, LINDE 0091	0.216	0.043	98	1.67E+18	-50	51.6	0.0	25.8	51.6	103.3	53.3
Lower-Intmed Long.												
101-834	51874, LINDE 0091 / Flux Lot 3458	0.147	0.037	68	2.77E+18	-50	44.2	0.0	22.1	44.2	88.3	38.3
Girth												
Lower to Lower-Int Girth 301-871	4P6052, LINDE 0091 / Flux Lot 0145	0.047	0.049	31	1.77E+18	-50	16.8	0.0	8.4	16.8	33.5	-16.5

Table 3-2: Hatch 2 ART Values (54 EFPY)

Table 3-3: Hatch 1 Plate Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM
FOR HATCH UNIT 1 - BWR 4/MK I - Including Extended Power Uprate

BWR/3-6 PLATE

Surveillance Plate USE:

%Cu = 0.12

1st Capsule Fluence = 2.4×10^{17} n/cm^2
2nd Capsule Fluence = 4.6×10^{17} n/cm^2

Unirradiated to 1st Capsule Measured % Decrease = 4 (Charpy Curves)
Unirradiated to 2nd Capsule Measured % Decrease = -5 (Charpy Curves)

1st Rev 2 Predicted % Decrease = 9 (Rev 2, Figure 2)
2nd Rev 2 Predicted % Decrease = 10 (Rev 2, Figure 2)

Limiting Beltline Plate USE:

%Cu = 0.17

54 EFPY ¼ T Fluence = 2.51×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 19 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

19 % $\leq$ 21%, so vessel plates are bounded by equivalent margin analysis

Table 3-4: Hatch 1 Weld Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM

FOR HATCH UNIT 1 - BWR 4/MK I - Including Extended Power Uprate

BWR/2-6 WELD

Surveillance Weld USE:

%Cu = 0.30

1st Capsule Fluence = 2.4×10^{17} n/cm^2
2nd Capsule Fluence = 4.6×10^{17} n/cm^2

Unirradiated to 1st or 2nd Capsule Measured % Decrease = Unknown
1st to 2nd Capsule Measured % Decrease = -16 (Charpy Curves)

1st Rev 2 Predicted % Decrease = 19 (Rev 2, Figure 2)
2nd Rev 2 Predicted % Decrease = 22 (Rev 2, Figure 2)

Limiting Beltline Weld USE:

%Cu = 0.316

54 EFPY ¼ T Fluence = 2.51×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 33 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

33 % $\leq$ 34%, so vessel welds are bounded by equivalent margin analysis

Table 3-5: Hatch 2 Plate Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM

FOR HATCH UNIT 2 - BWR 4/MK I - Including Extended Power Uprate

BWR/3-6 PLATE

Surveillance Plate USE:

%Cu = 0.08

1st Capsule Fluence = 2.3×10^{17} n/cm^2

Measured % Decrease = 0 (Charpy Curves)

Reg. Guide Rev 2 Predicted % Decrease = 7 (Rev 2, Figure 2)

Limiting Beltline Plate USE:

%Cu = 0.11

54 EFPY ¼ T Fluence = 2.77×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 15 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

15 % $\leq$ 21%, so vessel plates are bounded by equivalent margin analysis

Table 3-6: Hatch 2 Weld Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM
FOR HATCH UNIT 2 - BWR 4/MK I - Including Extended Power Uprate

BWR/2-6 WELD

Surveillance Weld USE:

%Cu = 0.13

Capsule Fluence = 2.3×10^{17} n/cm^2

Capsule Measured % Decrease = -1 (Charpy Curves)

Rev 2 Predicted % Decrease = 11 (Rev 2, Figure 2)

Limiting Beltline Weld USE:

%Cu = 0.216

54 EFPY ¼ T Fluence = 1.77×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 24 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

24 % $\leq$ 34%, so vessel welds are bounded by equivalent margin analysis

4. PRESSURE-TEMPERATURE CURVES

4.1 BACKGROUND

Nuclear Regulatory Commission (NRC) 10CFR50 Appendix G [1] specifies fracture toughness requirements to provide adequate margins of safety during the operating conditions to which a pressure-retaining component may be subjected over its service lifetime. The ASME Code (Appendix G of Section XI [8]) forms the basis for the requirements of 10CFR50 Appendix G. The limits for pressure and temperature are required by 10CFR50 Appendix G for three categories of operation: (a) hydrostatic pressure tests and leak tests, (b) core not critical heatup/cooldown, and (c) core critical operation. The heat transfer characteristics for these three categories are: (a) isothermal conditions for the hydrotest, and (b and c) insulated outside surface and metal temperature equaling the fluid temperature for 100°F/hr heatup/cooldown thermal rate. Heat transfer characteristics for the other transient conditions were based on flow and temperature conditions in the thermal cycle diagrams. The condition that results in the highest required temperature for the limiting material determines the minimum allowable temperature for the vessel.

There are four vessel regions defined in the thermal cycle diagram that should be monitored against the Pressure-Temperature (P-T) curve operating limits:

- Closure flange region (Region A)
- Core beltline region (Region B)
- Upper vessel (Regions A & B)
- Lower vessel (Regions B & C)

The closure flange region includes the bolts, top head flange, vessel flange, and adjacent plates and welds. The core beltline is the vessel location adjacent to the active fuel, such that the neutron fluence is sufficient to cause a significant shift of RT_{NDT}. The remaining portion of the vessel (i.e., upper vessel, lower vessel) includes shells, components like the nozzles, the support skirt, and stabilizer brackets; these regions will be called the non-beltline region.

Under certain conditions, the minimum bottom head temperature can be significantly cooler than the beltline or closure flange region. These conditions can occur when the recirculation pumps are operating at low speed (or are off), and during water injection through the control rod drives. To account for these circumstances, individual temperature limits for the bottom head were established. Bottom head curves are not provided for the core critical curve, since during core critical operation the entire RPV follows the steam saturation curve that is well to the right of the core critical curve.

The P-T curves for the heatup and cooldown operating condition at a given EFPY apply for both the 1/4T and 3/4T locations. When combining pressure and thermal stresses, it is usually necessary to evaluate stresses at the 1/4T location (inside surface flaw) and the 3/4T location (outside surface flaw). This is because the thermal gradient tensile stress of interest is in the inner wall during cooldown and is in the outer wall during heatup. However, as a conservative simplification, the thermal gradient stress at 1/4T is assumed to be tensile for both heatup and cooldown. This results in the approach of applying the maximum tensile stress at the 1/4T location. This approach is conservative for two reasons: 1) the maximum stress is used regardless of flaw location, and 2) the irradiation effects cause the allowable toughness, K_{IR}, at 1/4T to be less than that at 3/4T for a given metal temperature. This approach causes no operational difficulties, since the BWR vessel metal temperature is at steam saturation conditions during normal operation, satisfying the heatup/cooldown curve limits.

Except for the independent bottom head curve, the applicable temperature is the greater of the 10CFR50 Appendix G minimum temperature requirement and the ASME Appendix G limits. A summary of the requirements is provided in Table 4-1.

There are three vessel regions that affect the operating limits: the non-beltline regions, the core beltline region, and the closure flange. The closure flange region limits are controlling at lower pressures primarily because of

10CFR50, Appendix G requirements as indicated in Table 4-1. The non-beltline and beltline region operating limits are evaluated according to procedures in 10CFR50, Appendix G [1], ASME Boiler and Pressure Vessel Code, Section XI, Appendix G [8], and Welding Research Council (WRC) Bulletin 175 [5]. The beltline region minimum temperature limits are adjusted to account for vessel irradiation.

Limiting composite curves are applicable for (a) hydrostatic pressure tests and leak tests, (b) core not critical heatup/cooldown, and (c) core critical operation. The individual curves used to construct the limiting curves are described in Tables 4-2 and 4-3, for Units 1 and 2, respectively. Tables 4-2 and 4-3 show the pressure range over which each curve used to construct the composite P-T curves is limiting. The curves consist of the 10CFR50 Appendix G bolt-up limits (limits for the closure flange region that are highly stressed by the bolt preload), the non-beltline bottom head curve, the non-beltline feedwater nozzle curve, and the beltline curve. During core critical operation the entire RPV follows the saturation curve that is well to the right of the core critical curve.

4.2 NON-BELTLINE REGIONS

Non-beltline regions are defined as the vessel locations that are remote from the active fuel and where the neutron fluence is not sufficient to cause any significant shift of RT_{NDT}. Non-beltline components include most nozzles, the closure flanges, some shell plates, the top and bottom head plates and the control rod drive (CRD) penetrations.

Detailed stress analyses of the non-beltline components were performed for the BWR/6 specifically for the purpose of fracture toughness analysis. The analyses took into account all mechanical loading and anticipated thermal transients. Transients considered include 100°F/hr start-up and shutdown, SCRAM, loss of feedwater heaters or flow, loss of recirculation pump flow, and all transients involving emergency core cooling injections. Primary membrane and bending stresses and secondary membrane and bending stresses due to the most severe of these transients were used according to the ASME Code [8] to develop plots of allowable pressure (P) versus temperature relative to the reference temperature (T - RT_{NDT}). Plots were developed for the limiting BWR/4 components: the feedwater nozzle (FW) and the CRD penetration (bottom head). All other components in the non-beltline regions are categorized under one of these two components.

The P-T curves for the non-beltline region were conservatively developed for a large BWR/6 (nominal inside diameter of 251 inches). The analysis is considered appropriate for Hatch Unit 1 and Hatch Unit 2 as the plant specific geometric values are bounded by the generic analysis for a large BWR/6, as determined from Equations 4-2 and 4-3. The generic value was adapted to the conditions at Hatch Unit 1 and Hatch Unit 2 by using plant specific RT_{NDT} values for the reactor pressure vessel (RPV). The presence of nozzles and CRD penetration holes of the upper vessel and bottom head, respectively, has made the analysis different from a shell analysis such as the beltline. This was the result of the stress concentrations and higher thermal stresses for certain transient conditions experienced by the upper vessel and the bottom head.

The non-beltline curves are based on the most limiting (conservative) properties of either the upper vessel region or the bottom head. The non-beltline curves are shifted based on the most limiting initial RT_{NDT} values for the appropriate non-beltline components; the initial RT_{NDT} values were obtained from [6,7]. The individual bottom head curve is based on the non-beltline bottom head curve described in the next section. A detailed description of the construction of each non-beltline curve is included in the following sections.

4.2.1 PRESSURE TEST - NON-BELTLINE, CURVE A (USING BOTTOM HEAD)

In a BWR/6 finite element analysis, the CRD penetration region was modeled to compute the local stresses for determination of the stress intensity factor, K_I. The results of that computation were K_I = 154.3 ksi-in$^{1/2}$ for an applied pressure of 1593 psig (1563 psig preservice hydrotest pressure at the top of the vessel plus 30 psig hydrostatic pressure at the bottom of the vessel). The computed value of (T - RT_{NDT}) was 161°F; the limit for the temperature change rate is 20°F/hr.

The CRD penetration region limits were established primarily for consideration of bottom head discontinuity stresses during pressure testing.

The CRD penetration stresses were obtained from finite element analysis. These stresses, and other inputs used in the generic calculations, are shown below:

$_{pm}$ = 35.87 ksi	$_{sm}$ = 0.30 ksi	$_{ys}$ = 47.68 ksi
$_{pb}$ = -0.30 ksi	$_{sb}$ = 1.50 ksi	t = 8.0 inch

The value of M_m from Figure G-2214-1 [8] was based on a thickness of 8.0 inches; hence, $t^{1/2}$ = 2.83. The stress to yield ratio, / $_{ys}$, was calculated to be 0.78. The resulting value obtained was:

$$M_m = 2.83$$

K_{Im} is calculated from the equation in Paragraph G-2214.1 [8]:

$$K_{Im} = M_m * \sigma_{pm} = 101.5 \text{ ksi-in}^{1/2}$$

K_{Ib} is calculated from the equation in Paragraph G-2214.2 [8]:

$$K_{Ib} = (2/3)\ M_m * \sigma_{pb} = -0.60 \text{ ksi-in}^{1/2}$$

The total K_I is therefore:

$$K_I = 1.5 (K_{Im} + K_{Ib}) + M_m * (\sigma_{sm} + (2/3) * \sigma_{sb}) = 154.3 \text{ ksi-in}^{1/2}$$

This equation includes a safety factor of 1.5 on primary stress.

The method to solve for ($T - RT_{NDT}$) for a specific K_I is based on the curve in Figure G-2210-1 in ASME Appendix G [8]:

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = \ln [(154.3 - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 161°F$$

The generic curve was generated by scaling 154.3 ksi-in$^{1/2}$ by the nominal pressures and calculating the associated ($T - RT_{NDT}$):

Pressure Test CRD Penetration K_I and ($T - RT_{NDT}$) as a Function Of Pressure

Nominal Pressure (psig)	K_I (ksi-in$^{1/2}$)	$T - RT_{NDT}$ (°F)
1563	154.3	161
1400	138.2	151
1200	118.5	138
1000	98.7	121
800	79.0	99
600	59.2	66
400	39.5	1

The highest RT_{NDT} values for the bottom head plates and welds are 10°F and 50°F, for Hatch 1 and 2, respectively [6,7]. The generic P-T curve is shifted by these values.

The P-T curve is dependent on the K_I value calculated, which is proportional to the stress and the crack depth according to the relationship:

$$K_I \quad (\; a)^{1/2}$$
(4-1)

The stress is proportional to R/t and, for the P-T curves, crack depth, *a*, is t/4. Thus, K_I is proportional to $R/(t)^{1/2}$. The generic curve value of $R/(t)^{1/2}$, based on the generic BWR/6 bottom head dimensions, is:

Generic: $R / (t)^{1/2} = 138 / (8)^{1/2} = 49 \text{ inch}^{1/2}$ (4-2)

The Hatch Unit 1 and Hatch Unit 2 specific bottom head dimensions are R = 110 inches and t = 5.38 inches minimum, resulting in:

Hatch Unit 1 and Unit 2 specific:

$R / (t)^{1/2} = 110/ (5.38)^{1/2} = 47 \text{ inch}^{1/2}$ (4-3)

Since the generic value of $R/(t)^{1/2}$ is larger than that for Hatch Unit 1 and Hatch Unit 2, the generic P-T curve is conservative when applied to the Hatch Unit 1 and Hatch Unit 2 bottom heads.

4.2.2 CORE NOT CRITICAL HEATUP/COOLDOWN - NON-BELTLINE CURVE B (USING BOTTOM HEAD)

As discussed previously, the CRD penetration region limits were established primarily for consideration of bottom head discontinuity stresses during pressure testing. Heatup/cooldown limits were calculated by increasing the safety factor in Section 4.2.1 from 1.5 to 2.0, on the assumption that the conservative factor of 3.0 on bottom head pressure stress bounds the thermal stresses occurring during heatup/cooldown.

Subsequent analysis examined CRD penetration region limits for several emergency conditions involving severe bottom head thermal conditions. The transients with the most severe bottom head conditions were sudden start of an idle recirculation loop (cooldown) and improper start-up, or black start, from a hot standby condition with bottom head drain closed (heatup). The sudden start causes a step-change cooldown of 178°F. The improper start-up sequence involves a step-change heatup of 348°F. The result of CRD penetration region fracture toughness analysis for these conditions showed comparable P-T limits to those established assuming 3.0 times nominal pressure stress. Therefore, the CRD penetration region limits are adequate to assure structural integrity for heatup/cooldown step-changes in excess of 100°F.

The calculated value of K_I for pressure test is multiplied by a safety factor (SF) of 1.5, per ASME Appendix G [8] for comparison with K_{IR}, the material fracture toughness. A safety factor of 2.0 is used for the core not critical. Therefore, the K_I value for the core not critical condition is $(154.3 / 1.5) * 2.0 = 205.7$ ksi-in$^{1/2}$.

Therefore, the method to solve for $(T - RT_{NDT})$ for a specific K_I is also based on the curve in Figure G-2210-1 in ASME Appendix G [8] for the core not critical:

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = \ln [(205.7 - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 184°F$$

The generic curve was generated by scaling 205.7 ksi-in$^{1/2}$ by the nominal pressures and calculating the associated (T - RT_{NDT}):

Core Not Critical CRD Penetration K_I and (T - RT_{NDT})
as a Function of Pressure

Nominal Pressure (psig)	K_I (ksi-in$^{1/2}$)	T - RT_{NDT} (°F)
1563	205.7	184
1400	184.2	175
1200	157.9	162
1000	131.6	147
800	105.3	127
600	79.0	99
400	52.6	50

The highest RT_{NDT} values for the bottom head plates and welds is 10°F and 50°F,for Hatch 1 and 2, respectively. The generic P-T curve is shifted by these values.

4.2.3 PRESSURE TEST - NON-BELTLINE CURVE A (USING FEEDWATER NOZZLE/UPPER VESSEL REGION)

CBI Nuclear (CBIN) modeled the 251-inch BWR/6 feedwater nozzles to compute local stresses for determination of the stress intensity factor, K_I. The result of that computation was K_I = 143.1 ksi-in$^{1/2}$ for an applied pressure of 1563 psig preservice hydrotest pressure. The computed value of (T - RT_{NDT}) was 154°F. The respective flaw depth and orientation used in this calculation is perpendicular to the maximum stress (hoop) at a depth of 1/4T through the corner thickness.

To evaluate the CBIN result, K_I is calculated for the upper vessel nominal stress, PR/t, according to the methods in ASME Code Appendix G (Section III or XI). The result is compared to that determined by CBIN in order to quantify the K magnification associated with the stress concentration created by the feedwater nozzles.

A calculation of K_I is shown below using the BWR/6, 251-inch dimensions:

Vessel Radius, R	126.7 inches
Vessel Thickness, t	6.5 inches
Vessel Pressure, P	1563 psig

Pressure stress: σ = PR/t = 1563 psig 126.7 inches / (6.5 inches) = 30,466 psi

The factor F (a/r_n) from Figure A5-1 of WRC-175 [5] is 1.6 where :

a =	lesser of 1/4 t_n or 1/4 t_v	
t_n =	thickness of nozzle	= 7.13 inches
t_v =	thickness of vessel	= 6.5 inches
r_n =	apparent radius of nozzle	= $r_i + 0.29\ r_c$
r_i =	actual inner radius of nozzle	= 6 inches
r_c =	nozzle radius (nozzle corner radius)	= 4.0 inches

Thus, a/r_n = 1.63 / 6.94 = 0.23 and the ratio of K_I around the feedwater nozzle to the membrane stress · ($a)^{1/2}$ at places with no geometric discontinuity is 1.6.

Including the safety factor of 1.3, the stress intensity factor, K_I, is $1.3*\sigma*(\pi a)^{1/2} *F(a/r_n)$:

$$\text{Nominal } K_I = 1.3 \cdot 30.466 \cdot (\pi \cdot 1.63)^{1/2} \cdot 1.6 = 143 \text{ ksi-in}^{1/2}$$

The method to solve for (T - RT_{NDT}) for a specific K_I is based on the curve in Figure G-2210-1 in ASME Appendix G [8]:

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 1n [(143 - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 154°F$$

The generic pressure test P-T curve was generated by scaling 143 ksi-in$^{1/2}$ by the nominal pressures and calculating the associated (T - RT_{NDT}):

Pressure Test Feedwater Nozzle K_I and (T - RT_{NDT})
as a Function of Pressure

Nominal Pressure (psig)	K_I (ksi-in$^{1/2}$)	(T - RT_{NDT}) (°F)
1563	143	154
1400	128	145
1200	110	131
1000	92	114
800	73	91
600	55	56
400	37	-16

The P-T curve is dependent on the K_I value calculated, which is proportional to the stress and the crack depth according to the relationship:

$$K_I \propto \sigma (\pi a)^{1/2}$$

The stress is proportional to R/t and, for the P-T curves, crack depth, *a*, is t/4. Thus, K_I is proportional to $R/(t)^{1/2}$.

The generic curve value of $R/(t)^{1/2}$, based on the BWR/6, 251-inch feedwater nozzle dimensions is:

Generic: $R/(t)^{1/2} = 126.7 / (6.5)^{1/2} = 49.7 \text{ inch}^{1/2}$

where t is the nominal vessel thickness. The Hatch Unit 1 and Hatch Unit 2 specific vessel shell dimensions applicable to the feedwater nozzle location are R = 110 inches and t = 5.38 inches nominal.

Hatch Unit 1 and Unit 2 specific: $R/(t)^{1/2} = 110 / (5.38)^{1/2} = 47.4 \text{ inch}^{1/2}$

Since the generic value of $R/(t)^{1/2}$ is greater than that for Hatch Unit 1 and Hatch Unit 2, the generic P-T curve is conservative when applied to the Hatch Unit 1 and Hatch Unit 2 feedwater nozzles.

As discussed below, the highest RT_{NDT} values for the nozzle materials are 40°F and 26°F, for Hatch 1 and 2, respectively. The generic pressure test P-T curve is applied to the Hatch Unit 1 and Hatch Unit 2 feedwater nozzle curves by shifting the P vs. (T - RT_{NDT}) values above to reflect the RT_{NDT} values of 40°F and 26°F.

4.2.4 CORE NOT CRITICAL HEATUP/COOLDOWN - NON-BELTLINE CURVE B (USING FEEDWATER NOZZLE/UPPER VESSEL REGION)

The feedwater nozzle was selected to represent non-beltline components for fracture toughness analyses because the stress conditions are the most severe experienced in the vessel. In addition to the more severe pressure and piping load stresses resulting from the nozzle discontinuity, the feedwater nozzle region experiences relatively cold feedwater flow in hotter vessel coolant.

Stresses are taken from finite element analysis done specifically for fracture toughness analysis purposes. Analyses were performed for all feedwater nozzle transients that involve rapid temperature changes. The most severe of these was normal operation with cold 40°F feedwater injection, which is equivalent to hot standby.

The non-beltline curves based on feedwater nozzle limits were calculated according to the methods for nozzles in Appendix 5 of the Welding Research Council (WRC) Bulletin 175 [5].

The stress intensity factor for a nozzle flaw under primary stress conditions (K_{IP}) is given in WRC Bulletin 175 Appendix 5 [5] by the expression for a flaw at a hole in a flat plate:

$$K_{IP} = SF \cdot \quad (\; a)^{1/2} \cdot F(a/r_n) \qquad (4\text{-}4)$$

where SF is the safety factor applied per WRC Bulletin 175 [5] recommended ranges, and $F(a/r_n)$ is the shape correction factor.

Finite element analysis of a nozzle corner flaw was performed to determine appropriate values of $F(a/r_n)$ for Equation 4-4. These values are shown in Figure A5-1 of WRC Bulletin 175 [5].

The stresses used in Equation 4-4 were taken from BWR/6 design stress reports for the feedwater nozzle. The stresses considered are primary membrane, $_{pm}$, and primary bending, $_{pb}$. Secondary membrane, $_{sm}$, and secondary bending, ${}_{sb}$, stresses are included in the total K_I by using ASME Appendix G [8] methods for secondary portion, K_{Is}:

$$K_{Is} = M_m ({}_{sm} + (2/3) \cdot {}_{sb})$$
(4-5)

In the case where the total stress exceeded yield stress, a plasticity correction factor was applied based on the recommendations of WRC Bulletin 175 Section 5.C.3 [5]. However, the correction was not applied to primary membrane stresses because stresses that are based on equilibrium considerations (i.e., primary membrane) are not displacement controlled and are not reduced or changed by deformation of the component. K_{IP} and K_{Is} are added to obtain the total value of stress intensity factor, K_I. A safety factor of 1.6 is applied to primary stresses for core not critical heatup/cooldown conditions.

Once K_I was calculated, the following relationship was used to determine (T - RT_{NDT}). The highest RT_{NDT} for the appropriate non-beltline components was then used to establish the P-T curves.

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160 \qquad (4\text{-}6)$$

Example: Core Not Critical Heatup/Cooldown Calculation for Feedwater Nozzle/Upper Vessel Region

The non-beltline core not critical heatup/cooldown curve was based on the feedwater nozzle generic analysis, where feedwater injection of 40°F into the vessel while at operating conditions (551.4°F and 1050 psig) was the limiting normal or upset condition from a brittle fracture perspective. The feedwater nozzle corner stresses were obtained from finite element analysis. These stresses, and other inputs used in the generic calculations, are shown below:

${}_{pm}$ = 20.49 ksi	${}_{sm}$ = 16.19 ksi	${}_{ys}$ = 45.0 ksi	t = 7.5 inch
${}_{pb}$ = 0.22 ksi	${}_{sb}$ = 19.04 ksi	*a* = 1.88 inch	r_n = 6.94 inch

In this case the total stress, 55.94 ksi, exceeds the yield stress, ${}_{ys}$, so the correction factor, R, is calculated to consider the nonlinear effects in the plastic region according to the following equation based on the assumptions and recommendation of WRC Bulletin 175 [5]. (The value of specified yield stress is for the material at the temperature under consideration. For conservatism, the temperature assumed for the crack root is the inside surface temperature.)

$$R = [\ _{ys} - \ _{pm} + ((\ _{total} - \ _{ys}) / 30)] / (\ _{total} - \ _{pm}) \quad (4\text{-}7)$$

For the stresses given, the ratio, R = 0.70. Therefore, all the stresses are adjusted by the factor 0.70, except for $_{pm}$. The resulting stresses are:

$$_{pm} = 20.49 \text{ ksi} \qquad _{sm} = 11.33 \text{ ksi}$$
$$_{pb} = 0.15 \text{ ksi} \qquad _{sb} = 13.33 \text{ ksi}$$

The value of M_m from Figure G-2214-1 [8] was based on a thickness of 7.5 inches; hence, $t^{1/2} = 2.74$. The stress to yield ratio, $/\ _{ys}$, was conservatively assumed to be 1.0. The resulting value obtained was: $M_m = 2.84$.

The value $F(a/r_n)$, taken from Figure A5-1 of WRC Bulletin 175 [5] for an a/r_n of 0.27, is 1.5; however, 1.6 is used to be conservative.

$$F\,(a / r_n) = 1.6$$

K_{IP} is calculated from Equation 4-4:

$$K_{IP} = 1.6 \cdot (20.49 + 0.15) \cdot (\ \cdot 1.88)^{1/2} \cdot 1.6$$
$$K_{IP} = 128.4 \text{ ksi-in}^{1/2}$$

K_{Is} is calculated from Equation 4-5:

$$K_{Is} = 2.84 \cdot (11.33 + 2/3 \cdot 13.33)$$
$$K_{Is} = 57.4 \text{ ksi-in}^{1/2}$$

The total K_I is, therefore, 186 ksi-in$^{1/2}$.

The total K_I is substituted into Equation 4-6 to solve for $(T - RT_{NDT})$:

$(T - RT_{NDT})$ = ln [(186 - 26.78) / 1.223] / 0.0145 - 160

$(T - RT_{NDT})$ = 176°F

The generic curve was generated by scaling the stresses used to determine the K_I; this scaling was performed after the adjustment to stresses above yield. The primary stresses were scaled by the nominal pressures, while the secondary stresses were scaled by the temperature difference of the 40°F water injected into the hot reactor vessel nozzle. In the base case that yielded a K_I value of 186 ksi-in$^{1/2}$, the pressure is 1050 psig and the hot reactor vessel temperature is 551.4°F. Since the reactor vessel temperature follows the saturation temperature curve, the secondary stresses are scaled by $(T_{saturation}$ - 40) / (551.4 - 40). From K_I the associated $(T - RT_{NDT})$ can be calculated:

Core Not Critical Feedwater Nozzle K_I and $(T - RT_{NDT})$ as a Function of Pressure

Nominal Pressure (psig)	Saturation Temp. (°F)	K_I (ksi-in$^{1/2}$)	$(T - RT_{NDT})$ (°F)
1563	604	226	191
1400	588	213	187
1200	557	198	181
1050	551	186	176
1000	546	182	174
800	520	166	167
600	489	146	156
400	448	115	135

The highest non-beltline RT_{NDT} values for the feedwater region components are 40°F and 26°F (steam outlet nozzle) for Hatch Unit 1 and Hatch Unit 2, respectively [6,7]. The generic curve is applied to the Hatch Unit 1 and Hatch Unit 2 upper vessels by shifting the P vs. $(T - RT_{NDT})$ values above to reflect the RT_{NDT} values of 40°F and 26°F.

4.3 CORE BELTLINE REGION

The pressure-temperature (P-T) operating limits for the beltline region are determined according to the ASME Code. As the beltline fluence increases with the increase in operating life, the P-T curves shift to a higher temperature.

The stress intensity factors (K_I), calculated for the beltline region according to ASME Code Appendix G procedures [8], were based on a combination of pressure and thermal stresses for a 1/4T flaw in a flat plate. The pressure stresses were calculated using thin-walled cylinder equations. Thermal stresses were calculated assuming the through-wall temperature distribution of a flat plate; values were calculated for 100°F/hr thermal gradient. The shift value of the most limiting ART material was used to adjust the RT_{NDT} values for the P-T limits.

4.3.1 BELTLINE REGION - PRESSURE TEST

The methods of ASME Code Section XI, Appendix G [8] are used to calculate the pressure test beltline limits. The vessel shell, with an inside radius (R) to minimum thickness (t_{min}) ratio of 15, is treated as a thin-walled cylinder. The maximum stress is the hoop stress, given as:

$$_{m} = PR / t_{min} \qquad (4\text{-}8)$$

The stress intensity factor, K_{Im}, is calculated using Figure G-2214-1 of the ASME Code Section XI, Appendix G [8], accounting for the proper ratio of stress to yield strength. Figure G-2214-1 was taken from Welding Research Council (WRC) Bulletin 175 [5], based on a 1/4T radial flaw with a six-to-one aspect ratio (length of 1.5T). The flaw is oriented normal to the maximum stress direction, in this case a vertically oriented flaw. This orientation is used even in the case where the circumferential weld is the limiting beltline material.

The calculated value of K_{Im} for pressure test is multiplied by a safety factor (SF) of 1.5, per ASME Appendix G [8] for comparison with K_{IR}, the material fracture toughness. A safety factor of 2.0 is used for the core not critical and core critical conditions.

The relationship between K_{IR} and temperature relative to reference temperature (T - RT_{NDT}) is shown in Figure G-2210-1 of ASME Section XI Appendix G [8], represented by the relationship:

$$K_{Im} \cdot SF = K_{IR} = 1.223 \exp[0.0145 (T - RT_{NDT} + 160)] + 26.78 \qquad (4\text{-}9)$$

This relationship is derived in the Welding Research Council (WRC) Bulletin 175 [5] as the lower bound of all dynamic fracture toughness and crack arrest toughness data. This relationship provides values of pressure versus temperature (from K_{IR} and (T - RT_{NDT}), respectively).

GE's current practice for the pressure test curve is to add a stress intensity factor, K_{It}, for a heatup/cooldown rate of 20°F/hr to provide operating flexibility. For the core not critical and core critical condition curves, a stress intensity factor is added for a heatup/cooldown rate of 100°F/hr. The K_{It} calculation for a heatup/cooldown rate of 100°F/hr is described in Sections 4.3.3 and 4.3.4.

4.3.2 CALCULATIONS FOR THE BELTLINE REGION - PRESSURE TEST

This sample calculation is for a pressure test pressure of 1105 psig at 54 EFPY for Hatch Unit 1. The following inputs were used in the beltline limit calculation:

Adjusted RT_{NDT} = Initial RT_{NDT} + Shift	A = -20 + 187.2 = 167.2 °F (Based on ART values in Section 3)
Vessel Height	H = 825 inches
Bottom of Active Fuel Height	B = 208.5 inches
Vessel Radius (to inside of clad)	R = 110 inches
Minimum Vessel Thickness (without clad)	t = 5.38 inches
Limiting Beltline Material Yield Strength	$_y$ = 64.4 ksi

Pressure is calculated to include hydrostatic pressure for a full vessel:

$$P = 1105 \text{ psi} + (H - B)\ 0.0361 \text{ psi/inch} = P \text{ psig} \qquad (4\text{-}10)$$

$$= 1105 + (825 - 208.5)\ 0.0361 = 1127 \text{ psig}$$

Pressure stress:

$$= PR/t \qquad (4\text{-}11)$$
$$= 1.127 \cdot \ 110 / 5.38 = 23.0 \text{ ksi}$$

The factor M_m (= 2.23) depends on (/ $_y$ = 23.0 / 64.4) and $t^{1/2}$ and is determined from Figure G-2214-1 of the ASME Code Appendix G [8], where t is the minimum vessel thickness without cladding. The stress intensity factor for the pressure stress is $K_{Im} = M_m \cdot$ The stress intensity factor for the thermal stress, K_{It}, is calculated as described in Section 4.3.4 except that the value of "G" is 20°F/hr instead of 100°F/hr.

Equation 4-9 can be rearranged, and 1.5 K_{Im} substituted for K_{IR}, to solve for (T - RT_{NDT}). Using ASME Section XI Appendix G, Fig. G-2210-1 [8], K_{Im}= 51.3, and K_{It} = 1.73 for a 20°F/hr heatup/cooldown rate with a vessel thickness, t, that includes cladding:

$$(T - RT_{NDT}) = \ln[(1.5 \cdot K_{Im} + K_{It} - 26.78) / 1.223] / 0.0145 - 160 \qquad (4\text{-}12)$$
$$= \ln[(1.5 \cdot 51.3 + 1.73 - 26.78) / 1.223] / 0.0145 - 160$$
$$= 98.5°F$$

T can be calculated by adding the adjusted RT_{NDT}:

$$T = 98.5 + 167 = 265.5°F \qquad \text{for } P = 1105 \text{ psig}$$

4.3.3 BELTLINE REGION - CORE NOT CRITICAL HEATUP/COOLDOWN

The beltline curves for core not critical heatup/cooldown conditions are influenced by pressure stresses and thermal stresses, according to the relationship in ASME Section XI Appendix G [8]:

$$K_{IR} = 2.0 \cdot K_{Im} + K_{It} \qquad (4\text{-}13)$$

where K_{Im} is primary membrane K due to pressure and K_{It} is radial thermal gradient K due to heatup/cooldown.

The pressure stress intensity factor K_{Im} is calculated by the method described above, the only difference being the larger safety factor applied. The thermal gradient stress intensity factor calculation is described below.

The thermal stresses in the vessel wall are caused by a radial thermal gradient that is created by changes in the adjacent reactor coolant temperature in heatup or cooldown conditions. The stress intensity factor is computed by multiplying the coefficient M_t from Figure G-2214-2 of ASME Appendix G [8] by the through-wall temperature gradient T_w, given that the temperature gradient has a through-wall shape similar to that shown in Figure G-2214-3 of ASME Appendix G [8]. The relationship used to compute the through-wall T_w is based on one-dimensional heat conduction through an insulated flat plate:

$$^2T(x,t) / \quad x^2 = 1 / \quad (\quad (x,t) / \quad t)$$
(4-14)

where T(x,t) is temperature of the plate at depth x and time t, and is the thermal diffusivity.

The maximum stress will occur when the radial thermal gradient reaches a quasi-steady state distribution, so that $T(x,t) / \quad t = dT(t) / dt = G$, where G is the heatup/cooldown rate, normally 100°F/hr. The differential equation is integrated over x for the following boundary conditions:

1. Vessel inside surface (x = 0) temperature is the same as coolant temperature, T_0.
2. Vessel outside surface (x = C) is perfectly insulated; the thermal gradient dT/dx = 0.

The integrated solution results in the following relationship for wall temperature:

$$T = Gx^2 / 2 \quad - GCx / \quad + T_0$$
(4-15)

This equation is normalized to plot $(T - T_0)$ / T_w versus x / C.

The resulting through-wall gradient compares very closely with Figure G-2214-3 of ASME Appendix G [8]. Therefore, T_w calculated from Equation 4-14 is used with the appropriate M_t of Figure G-2214-2 of ASME Appendix G [8] to compute K_{It} for heatup and cooldown.

The M_t relationships were derived in the Welding Research Council (WRC) Bulletin 175 [5] for infinitely long cracks of 1/4T and 1/8T. For the flat plate geometry and radial thermal gradient, orientation of the crack is not important.

4.3.4 CALCULATIONS FOR THE BELTLINE REGION CORE NOT CRITICAL HEATUP/COOLDOWN

This sample calculation is for a pressure of 1105 psi for 54 EFPY.

The core not critical heatup/cooldown curve at 1105 psig uses the same K_{Im} as the pressure test curve, but with a safety factor of 2.0 instead of 1.5. The increased safety factor is used because the heatup/cooldown cycle represents an operational rather than test condition that necessitates a higher safety factor. In addition, there is a K_{It} term for the thermal stress. The additional inputs used to calculate K_{It} are:

Heatup/cooldown rate, normally 100°F/hr, G = 100 °F/hr

Minimum vessel thickness, including clad thickness, C = 0.47 ft (5.69 inches)

Thermal diffusivity at 550°F (most conservative value), = 0.354 ft^2/ hr [9]

Equation 4-15 can be solved for the through-wall temperature (x = C), resulting in the absolute value of T for heatup or cooldown of:

$$T = GC^2 / 2 \qquad (4\text{-}16)$$

$$= 100\,(0.47)^2 / (2 \bullet 0.354) = 31.2°F$$

The analyzed case for thermal stress is a 1/4T flaw depth with wall thickness of C. The corresponding value of M_t (=0.2775) can be found from ASME Appendix G, Figure G-2214-2 [8]. Thus the thermal stress intensity factor, $K_{It} = M_t \cdot T = 8.66$, can be calculated.

The pressure and thermal stress terms are substituted into Equation 4-9 to solve for (T - RT_{NDT}):

$$(T - RT_{NDT}) = \ln[((2 \cdot K_{Im} + K_{It}) - 26.78) / 1.223] / 0.0145 - 160 \qquad (4\text{-}17)$$

$$= \ln[(2 \cdot 51.3 + 8.66 - 26.78) / 1.223] / 0.0145 - 160$$

$$= 132\ °F$$

T can be calculated by adding the adjusted RT_{NDT}:

$$T = 132 + 167 = 299\ °F \quad \text{for } P = 1105 \text{ psig}$$

4.4 CLOSURE FLANGE REGION

10CFR50 Appendix G [1] sets several minimum requirements for pressure and temperature in addition to those outlined in the ASME Code, based on the closure flange region RT_{NDT}. In some cases, the results of analysis for other regions exceed these requirements and closure flange limits do not affect the shape of the P-T curves. However, some closure flange requirements do impact the curves, as is true with Hatch Unit 1 and Hatch Unit 2 at low pressures.

The original ASME Code requirement for bolt-up was at qualification temperature (T_{30L}) plus 60°F. The Code used for the currently licensed P-T curves is the 1989 ASME Code, no addenda. The ASME Code requirements state in Paragraph G-2222(c) that, for application of full bolt preload and reactor pressure up to 20% of hydrostatic test pressure, the RPV metal temperature must be at RT_{NDT} or greater. The approach used for Hatch Unit 1 and Hatch Unit 2 for the bolt-up temperature was based on a more conservative value of (RT_{NDT} + 60), or the LST of the bolting materials, whichever is greater. The 60°F adder is included by GE for two reasons: 1) the pre-1971 requirements of the ASME Code Section III, Subsection NA, Appendix G included the 60°F adder, and 2) inclusion of the additional 60°F requirement above the RT_{NDT} provides the additional assurance that a flaw size between 0.1 and 0.24 inches is acceptable. The limiting initial RT_{NDT} values for the closure flange region were 16°F for Unit 1 and 30°F for Unit 2 due to the flange, upper vessel and top head plate materials, and the LST of the closure studs was 70°F for both units, so the bolt-up temperature values used were 76°F (Unit 1) and 90°F (Unit 2). This conservatism is appropriate because bolt-up is one of the more limiting operating conditions (high stress and low temperature) for brittle fracture.

10CFR50 Appendix G, paragraph IV.A.2 [1] including Table 1, sets minimum temperature requirements for pressure above 20% hydrotest pressure based on the RT_{NDT} of the closure region. Curve A temperature must be no less than (RT_{NDT} + 90°F) and Curve B temperature no less than (RT_{NDT} + 120°F).

For pressures below 20% of preservice hydrostatic test pressure (312 psig) and with full bolt preload, the closure flange region metal temperature is required to be at RT_{NDT} or greater as described above. At low pressure, the ASME Code [8] allows the beltline and bottom head regions to experience even lower metal temperatures than the flange region RT_{NDT}. However, temperatures should not be permitted to be lower than 68°F for the reason discussed below.

The shutdown margin, provided in the Hatch Unit 1 and Hatch Unit 2 Technical Specification, is calculated for a water temperature of 68°F. Shutdown margin is the quantity of reactivity needed for a reactor core to reach criticality with the strongest-worth control rod fully withdrawn and all other control rods fully inserted. Although it may be possible to safely allow the water temperature to fall below this 68°F limit, further extensive calculations would be required to justify a lower temperature. The 76°F (Unit 1) and 90°F (Unit 2) limits apply when the head is on and tensioned and the 68°F limit when the head is off, while fuel is in the vessel. When the head is not tensioned and fuel is not in the vessel, the requirements of 10CFR50 Appendix G [1] do not apply, and there are no limits on the vessel temperatures.

4.5 CORE CRITICAL OPERATION REQUIREMENTS OF 10CFR50, APPENDIX G

Curve C, the core critical operation curve, is generated from the requirements of 10CFR50 Appendix G [1, Table 1]. Table 1 of [1] requires that core critical P-T limits be 40°F above any Curve A or B limits when pressure exceeds 20% of the pre-service system hydrotest pressure. Curve B is more limiting than Curve A, so limiting Curve C values are at least Curve B plus 40°F for pressures above 312 psig.

Table 1 of 10CFR50 Appendix G [1] indicates that for a BWR with water level within normal range for power operation, the allowed temperature for initial criticality at the closure flange region is (RT_{NDT} + 60°F) at pressures below

312 psig. This requirement makes the minimum criticality temperatures 76°F (Unit 1) and 90°F (Unit 2), based on RT_{NDT} values of 16°F and 30°F for Unit 1 and 2, respectively. In addition, above 312 psig the Curve C temperature must be at least the greater of RT_{NDT} of the closure region + 160°F or the temperature required for the hydrostatic pressure test (Curve A at 1105 psig). Therefore, this requirement causes a temperature shift in Curve C at 312 psig.

Table 4-1: Summary of the 10CFR50 Appendix G Requirements

Operating Condition and Pressure	Minimum Temperature Requirement
I. Hydrostatic Pressure Test & Leak Test (Core is Not Critical) - Curve A	
1. At ≤ 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 60°F*
2. At > 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 90°F
II. Normal operation (heatup and cooldown), including anticipated operational occurrences	
a. Core not critical - Curve B	
1. At ≤ 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 60°F*
2. At > 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 120°F
b. Core critical - Curve C	
1. At ≤ 20% of preservice hydrotest pressure, with the water level within the normal range for power operation	Larger of ASME Limits + 40°F or of a.1
2. At > 20% of preservice hydrotest pressure	Larger of ASME Limits + 40°F or of a.2 + 40°F or the minimum permissible temperature for the inservice system hydrostatic pressure test

*60°F adder is included by GE as an additional conservatism as discussed in Section 4.4

Table 4-2: Composite and Individual Curves Used To Construct Composite P-T Curves at 54 EFPY (Unit 1)

Curve	Curve Description	Curve Limiting Over Pressure Range, (Psig)
Curve A	10CFR50 Bolt-up Limits	0 - 410
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	none
	Beltline Limits	410 - 1400
Curve B	10CFR50 Bolt-up Limits	0 - 50
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	50-290
	Beltline Limits	290- 1400
Curve C	10CFR50 Bolt-up Limits	0 - 20
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	20-290
	Beltline Limits	290 - 1400

Note: The core critical operation curve is identical to the core not critical heatup/cooldown curve but shifted by 40°F, as required in 10CFR50, Appendix G [1]. Hence the methods used for determining the core not critical heatup/cooldown curves apply to the core critical curves, as well.

Table 4-3: Composite and Individual Curves Used To Construct Composite P-T Curves at 54 EFPY (Unit 2)

Curve	Curve Description	Curve Limiting Over Pressure Range, (Psig)
Curve A	10CFR50 Bolt-up Limits	0 - 610
	Bottom Head Limits (CRD Nozzle)	610-1400
	FW Nozzle Limits	none
	Beltline Limits	none
Curve B	10CFR50 Bolt-up Limits	0 - 90
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	90-960
	Beltline Limits	960-1400
Curve C	10CFR50 Bolt-up Limits	0 - 30
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	30-960
	Beltline Limits	960 - 1400

Note: The core critical operation curve is identical to the core not critical heatup/cooldown curve but shifted by 40°F, as required in 10CFR50, Appendix G [1]. Hence the methods used for determining the core not critical heatup/cooldown curves apply to the core critical curves, as well.

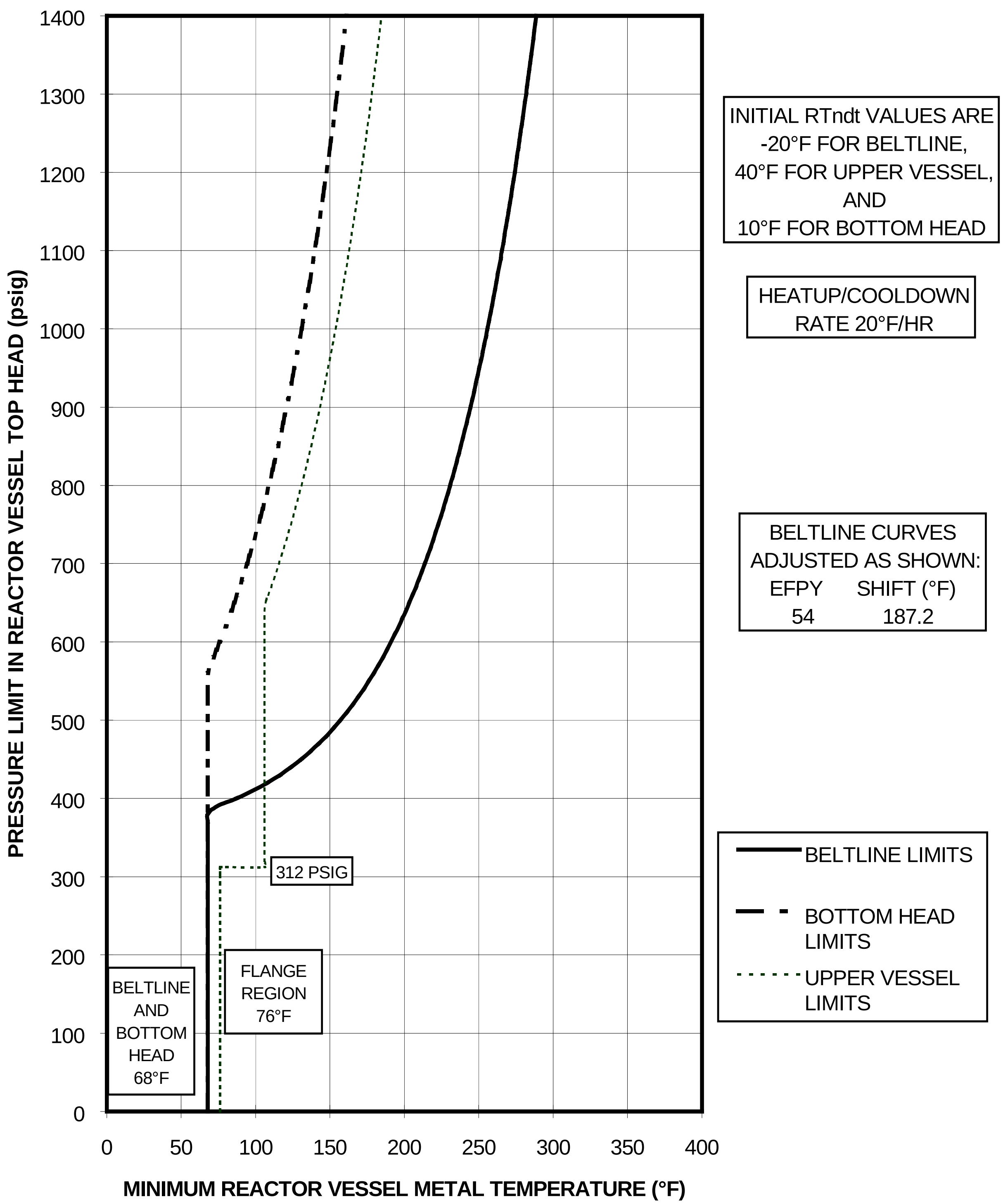

Figure 4-1: Pressure Test Curve (Curve A) [Unit 1]

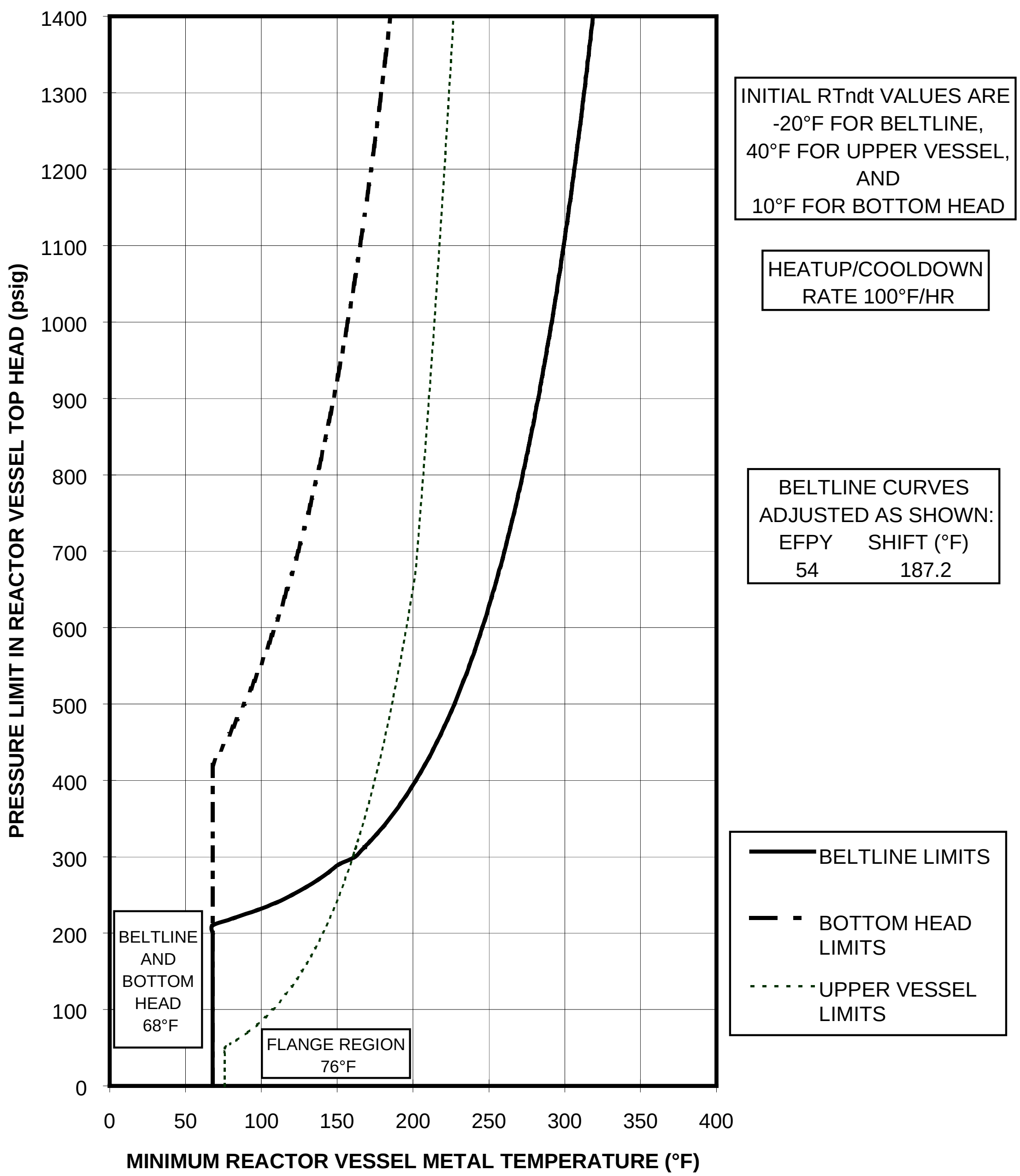

Figure 4-2: Non-Nuclear Heatup/Cooldown (Curve B) [Unit 1]

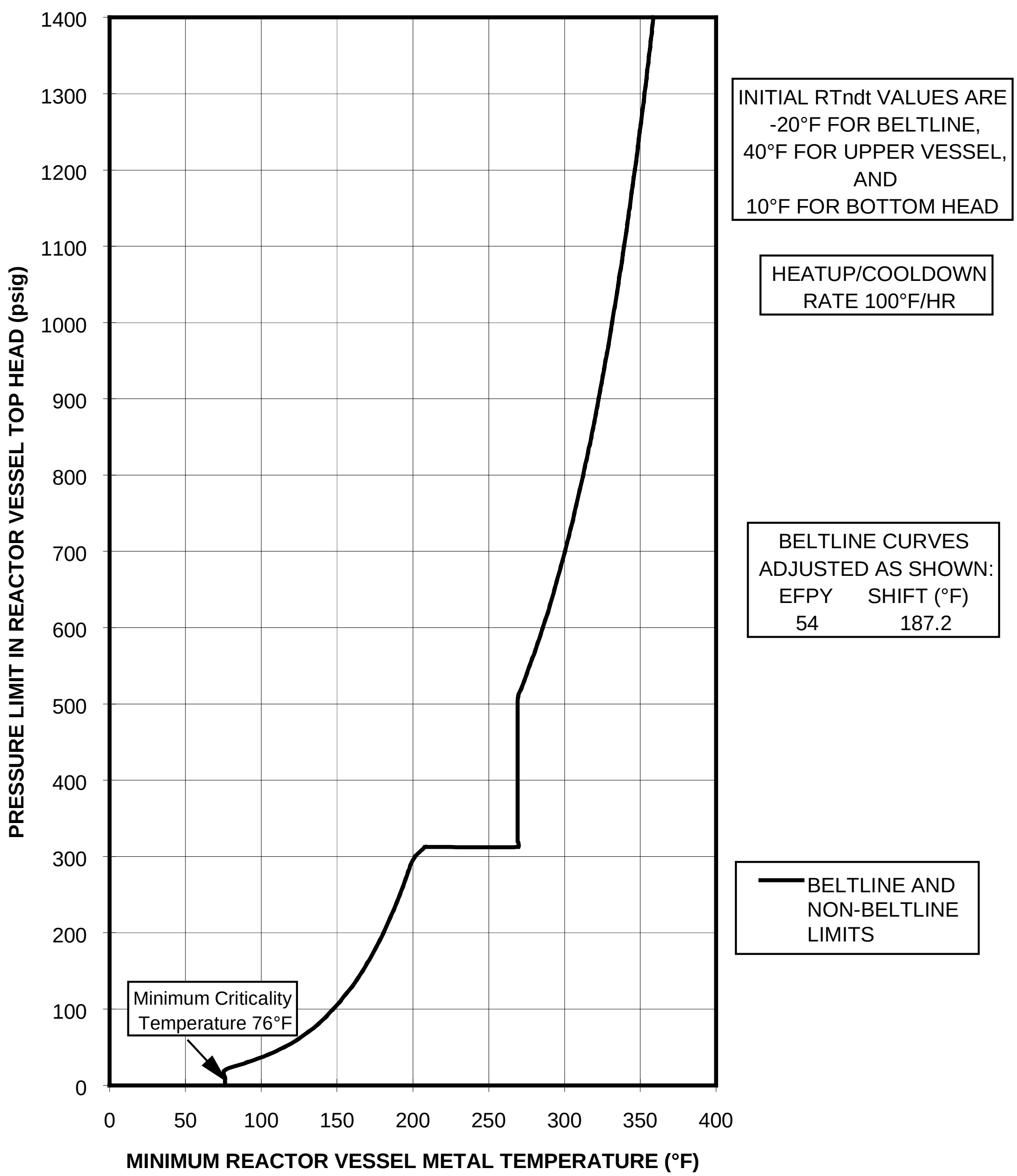

Figure 4-3: Core Critical Curve (Curve C) [Unit 1]

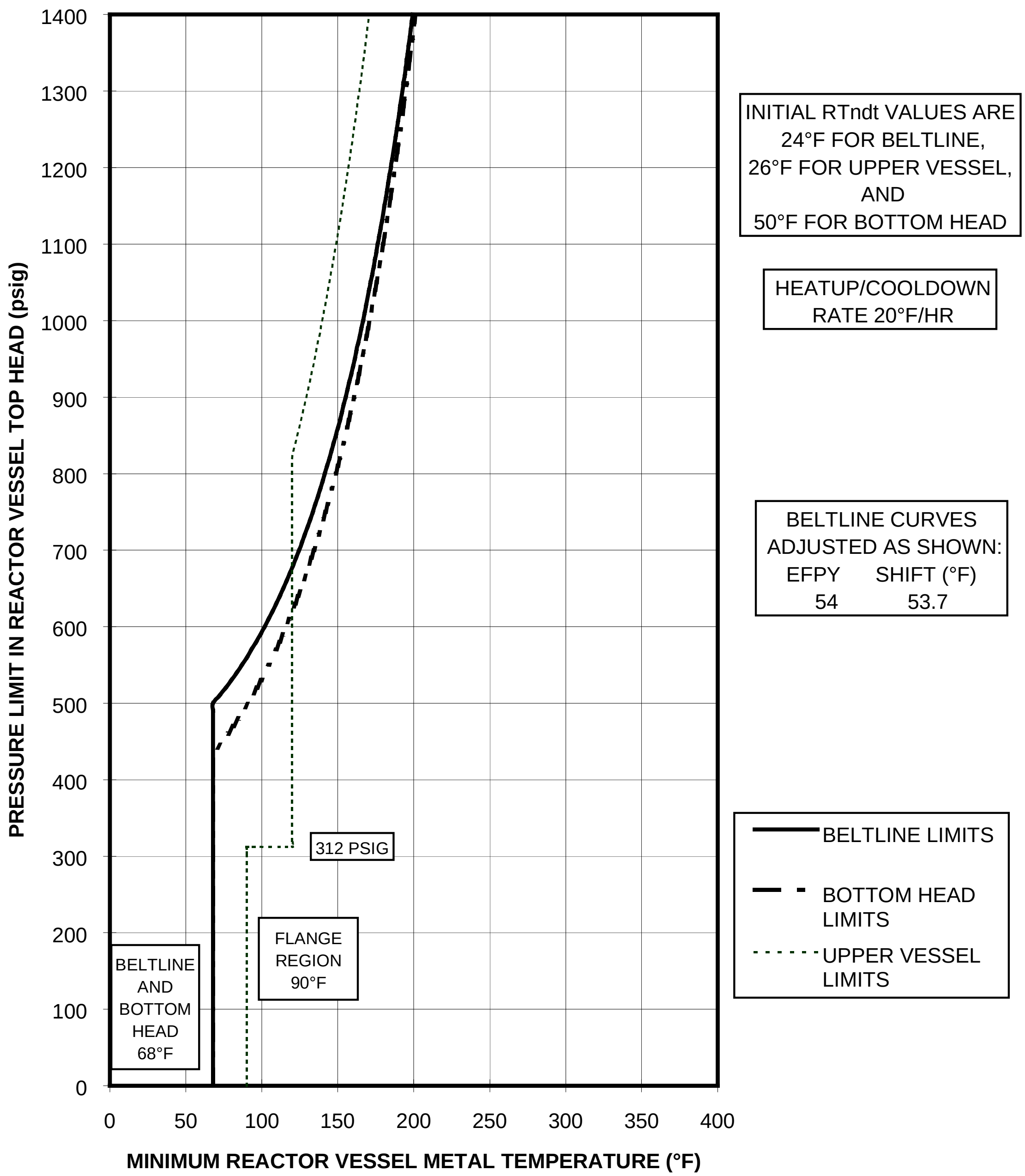

Figure 4-4: Pressure Test Curve (Curve A) [Unit 2]

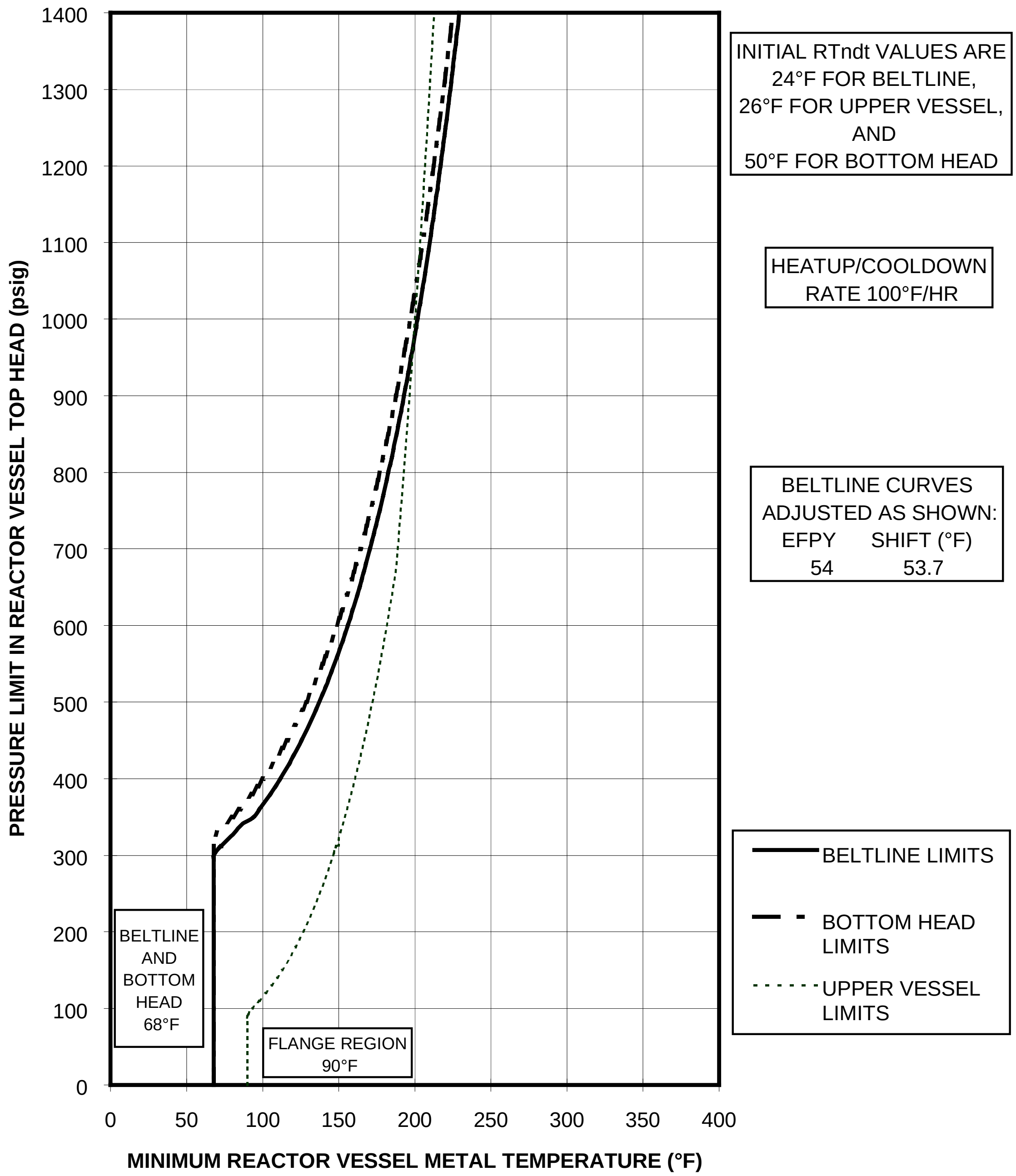

Figure 4-5: Non-Nuclear Heatup/Cooldown (Curve B) [Unit 2]

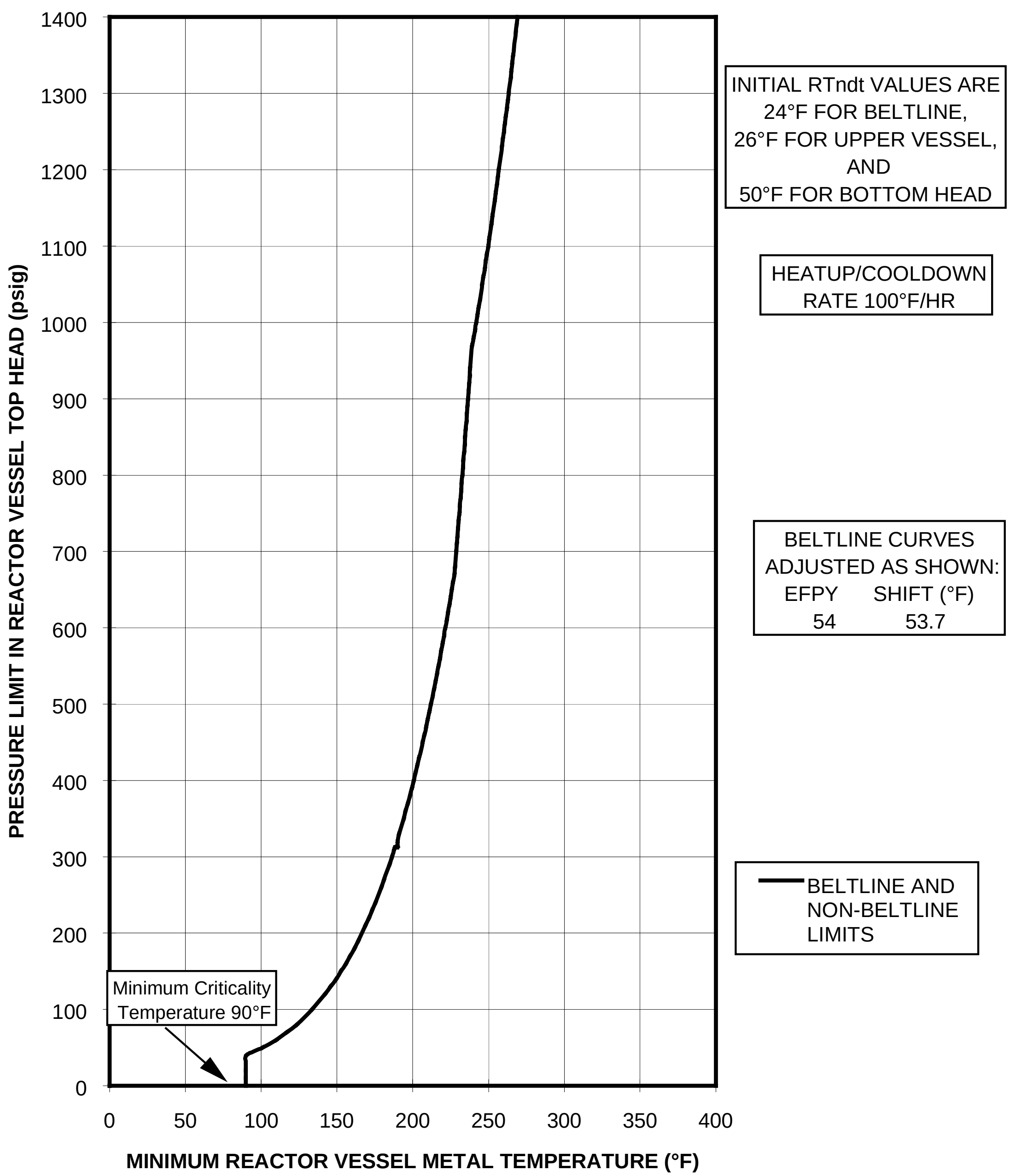

Figure 4-6: Core Critical Curve (Curve C) [Unit 2]

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	82.2	145.2	185.2
230	68.0	68.0	76.0	68.0	97.4	147.4	187.4
240	68.0	68.0	76.0	68.0	109.8	149.4	189.4

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
250	68.0	68.0	76.0	68.0	120.3	151.4	191.4
260	68.0	68.0	76.0	68.0	129.4	153.3	193.3
270	68.0	68.0	76.0	68.0	137.5	155.1	195.1
280	68.0	68.0	76.0	68.0	144.7	157.0	197.0
290	68.0	68.0	76.0	68.0	151.2	158.7	198.7
300	68.0	68.0	76.0	68.0	161.5	160.3	201.5
310	68.0	68.0	76.0	68.0	166.8	162.0	206.8
312.5	68.0	68.0	76.0	68.0	168.1	162.3	208.1
312.5	68.0	68.0	106.0	68.0	168.1	162.3	269.2
320	68.0	68.0	106.0	68.0	171.7	163.5	269.2
330	68.0	68.0	106.0	68.0	176.3	165.1	269.2
340	68.0	68.0	106.0	68.0	180.6	166.6	269.2
350	68.0	68.0	106.0	68.0	184.7	168.0	269.2
360	68.0	68.0	106.0	68.0	188.5	169.4	269.2
370	68.0	68.0	106.0	68.0	192.1	170.8	269.2
380	68.0	68.0	106.0	68.0	195.5	172.1	269.2
390	68.0	74.0	106.0	68.0	198.8	173.4	269.2
400	68.0	87.3	106.0	68.0	202.0	174.7	269.2
410	68.0	98.4	106.0	68.0	204.9	176.0	269.2
420	68.0	108.0	106.0	68.0	207.8	177.2	269.2
430	68.0	116.5	106.0	70.3	210.6	178.4	269.2
440	68.0	124.0	106.0	73.2	213.2	179.6	269.2
450	68.0	130.7	106.0	76.1	215.8	180.7	269.2
460	68.0	136.9	106.0	78.8	218.2	181.8	269.2
470	68.0	142.5	106.0	81.5	220.6	182.9	269.2
480	68.0	147.8	106.0	84.0	222.9	184.0	269.2
490	68.0	152.6	106.0	86.5	225.1	185.1	269.2

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
500	68.0	157.1	106.0	88.8	227.3	186.1	269.2
510	68.0	161.4	106.0	91.1	229.3	187.1	269.3
520	68.0	165.4	106.0	93.3	231.4	188.1	271.4
530	68.0	169.2	106.0	95.5	233.3	189.1	273.3
540	68.0	172.8	106.0	97.6	235.3	190.1	275.3
550	68.0	176.2	106.0	99.6	237.1	191.1	277.1
560	68.0	179.5	106.0	101.5	238.9	192.0	278.9
570	69.5	182.6	106.0	103.5	240.7	192.9	280.7
580	71.8	185.5	106.0	105.3	242.4	193.8	282.4
590	74.0	188.4	106.0	107.1	244.1	194.7	284.1
600	76.1	191.1	106.0	108.9	245.7	195.6	285.7
610	78.2	193.8	106.0	110.6	247.3	196.5	287.3
620	80.2	196.3	106.0	112.3	248.9	197.3	288.9
630	82.1	198.7	106.0	113.9	250.4	198.2	290.4
640	84.0	201.1	106.0	115.5	251.9	199.0	291.9
650	85.9	203.4	106.7	117.1	253.4	199.8	293.4
660	87.7	205.6	108.6	118.6	254.8	200.6	294.8
670	89.4	207.7	110.4	120.1	256.2	201.4	296.2
680	91.1	209.8	112.2	121.6	257.6	201.9	297.6
690	92.8	211.8	114.0	123.0	259.0	202.3	299.0
700	94.4	213.8	115.7	124.4	260.3	202.8	300.3
710	96.0	215.7	117.4	125.8	261.6	203.2	301.6
720	97.6	217.6	119.0	127.1	262.9	203.6	302.9
730	99.1	219.4	120.6	128.4	264.1	204.0	304.1
740	100.6	221.1	122.2	129.7	265.4	204.4	305.4
750	102.0	222.8	123.7	131.0	266.6	204.8	306.6
760	103.5	224.5	125.2	132.3	267.7	205.2	307.7

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
770	104.8	226.1	126.7	133.5	268.9	205.6	308.9
780	106.2	227.7	128.1	134.7	270.1	206.0	310.1
790	107.6	229.3	129.5	135.9	271.2	206.4	311.2
800	108.9	230.8	130.9	137.0	272.3	206.7	312.3
810	110.2	232.3	132.2	138.2	273.4	207.1	313.4
820	111.4	233.8	133.5	139.3	274.5	207.5	314.5
830	112.7	235.2	134.8	140.4	275.5	207.9	315.5
840	113.9	236.6	136.1	141.5	276.6	208.3	316.6
850	115.1	238.0	137.3	142.6	277.6	208.7	317.6
860	116.3	239.3	138.6	143.6	278.6	209.0	318.6
870	117.5	240.7	139.8	144.7	279.6	209.4	319.6
880	118.6	241.9	140.9	145.7	280.6	209.8	320.6
890	119.7	243.2	142.1	146.7	281.6	210.1	321.6
900	120.8	244.5	143.3	147.7	282.5	210.5	322.5
910	121.9	245.7	144.4	148.7	283.5	210.9	323.5
920	123.0	246.9	145.5	149.7	284.4	211.2	324.4
930	124.0	248.1	146.6	150.6	285.3	211.6	325.3
940	125.1	249.3	147.7	151.6	286.2	212.0	326.2
950	126.1	250.4	148.7	152.5	287.1	212.3	327.1
960	127.1	251.5	149.8	153.4	288.0	212.7	328.0
970	128.1	252.6	150.8	154.3	288.9	213.0	328.9
980	129.1	253.7	151.8	155.2	289.7	213.4	329.7
990	130.0	254.8	152.8	156.1	290.6	213.7	330.6
1000	131.0	255.9	153.8	157.0	291.4	214.1	331.4
1010	131.9	256.9	154.7	157.8	292.3	214.4	332.3
1020	132.9	257.9	155.7	158.7	293.1	214.8	333.1
1030	133.8	258.9	156.6	159.5	293.9	215.1	333.9

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1040	134.7	259.9	157.6	160.4	294.7	215.4	334.7
1050	135.6	260.9	158.5	161.2	295.5	215.8	335.5
1060	136.5	261.9	159.4	162.0	296.3	216.1	336.3
1070	137.3	262.8	160.3	162.8	297.1	216.5	337.1
1080	138.2	263.8	161.2	163.6	297.8	216.8	337.8
1090	139.0	264.7	162.0	164.4	298.6	217.1	338.6
1100	139.9	265.6	162.9	165.1	299.3	217.5	339.3
1110	140.7	266.5	163.7	165.9	300.1	217.8	340.1
1120	141.5	267.4	164.6	166.7	300.8	218.1	340.8
1130	142.3	268.3	165.4	167.4	301.5	218.4	341.5
1140	143.1	269.2	166.2	168.1	302.2	218.8	342.2
1150	143.9	270.0	167.0	168.9	303.0	219.1	343.0
1160	144.7	270.9	167.8	169.6	303.7	219.4	343.7
1170	145.5	271.7	168.6	170.3	304.4	219.7	344.4
1180	146.2	272.6	169.4	171.0	305.0	220.0	345.0
1190	147.0	273.4	170.2	171.7	305.7	220.4	345.7
1200	147.7	274.2	170.9	172.4	306.4	220.7	346.4
1210	148.5	275.0	171.7	173.1	307.1	221.0	347.1
1220	149.2	275.8	172.4	173.8	307.7	221.3	347.7
1230	149.9	276.6	173.2	174.5	308.4	221.6	348.4
1240	150.6	277.3	173.9	175.1	309.0	221.9	349.0
1250	151.3	278.1	174.6	175.8	309.7	222.2	349.7
1260	152.0	278.8	175.4	176.5	310.3	222.5	350.3
1270	152.7	279.6	176.1	177.1	311.0	222.8	351.0
1280	153.4	280.3	176.8	177.8	311.6	223.1	351.6
1290	154.1	281.1	177.5	178.4	312.2	223.4	352.2
1300	154.8	281.8	178.1	179.0	312.8	223.7	352.8

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1310	155.4	282.5	178.8	179.6	313.4	224.0	353.4
1320	156.1	283.2	179.5	180.3	314.0	224.3	354.0
1330	156.8	283.9	180.2	180.9	314.6	224.6	354.6
1340	157.4	284.6	180.8	181.5	315.2	224.9	355.2
1350	158.1	285.3	181.5	182.1	315.8	225.2	355.8
1360	158.7	286.0	182.1	182.7	316.4	225.5	356.4
1370	159.3	286.7	182.8	183.3	317.0	225.8	357.0
1380	159.9	287.3	183.4	183.9	317.6	226.1	357.6
1390	160.6	288.0	184.0	184.5	318.1	226.4	358.1
1400	161.2	288.6	184.7	185.0	318.7	226.7	358.7

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
0	68.0	68.0	90.0	68.0	68.0	90.0	90.0
10	68.0	68.0	90.0	68.0	68.0	90.0	90.0
20	68.0	68.0	90.0	68.0	68.0	90.0	90.0
30	68.0	68.0	90.0	68.0	68.0	90.0	90.0
40	68.0	68.0	90.0	68.0	68.0	90.0	90.5
50	68.0	68.0	90.0	68.0	68.0	90.0	101.2
60	68.0	68.0	90.0	68.0	68.0	90.0	109.9
70	68.0	68.0	90.0	68.0	68.0	90.0	117.1
80	68.0	68.0	90.0	68.0	68.0	90.0	123.4
90	68.0	68.0	90.0	68.0	68.0	90.0	128.7
100	68.0	68.0	90.0	68.0	68.0	93.5	133.5
110	68.0	68.0	90.0	68.0	68.0	97.9	137.9
120	68.0	68.0	90.0	68.0	68.0	102.1	142.1
130	68.0	68.0	90.0	68.0	68.0	106.1	146.1
140	68.0	68.0	90.0	68.0	68.0	109.6	149.6
150	68.0	68.0	90.0	68.0	68.0	112.8	152.8
160	68.0	68.0	90.0	68.0	68.0	115.8	155.8
170	68.0	68.0	90.0	68.0	68.0	118.8	158.8
180	68.0	68.0	90.0	68.0	68.0	121.6	161.6
190	68.0	68.0	90.0	68.0	68.0	124.2	164.2
200	68.0	68.0	90.0	68.0	68.0	126.6	166.6
210	68.0	68.0	90.0	68.0	68.0	128.9	168.9
220	68.0	68.0	90.0	68.0	68.0	131.2	171.2
230	68.0	68.0	90.0	68.0	68.0	133.4	173.4
240	68.0	68.0	90.0	68.0	68.0	135.4	175.4
250	68.0	68.0	90.0	68.0	68.0	137.4	177.4
260	68.0	68.0	90.0	68.0	68.0	139.3	179.3

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
270	68.0	68.0	90.0	68.0	68.0	141.1	181.1
280	68.0	68.0	90.0	68.0	68.0	143.0	183.0
290	68.0	68.0	90.0	68.0	68.0	144.7	184.7
300	68.0	68.0	90.0	68.0	68.0	146.3	186.3
310	68.0	68.0	90.0	68.0	71.5	148.0	188.0
312.5	68.0	68.0	90.0	68.0	72.9	148.3	188.3
312.5	68.0	68.0	120.0	68.0	72.9	150.0	190.0
320	68.0	68.0	120.0	68.0	76.8	150.0	190.0
330	68.0	68.0	120.0	70.1	81.6	151.1	191.1
340	68.0	68.0	120.0	75.4	86.1	152.6	192.6
350	68.0	68.0	120.0	80.2	94.0	154.0	194.0
360	68.0	68.0	120.0	84.8	97.9	155.4	195.4
370	68.0	68.0	120.0	89.0	101.6	156.8	196.8
380	68.0	68.0	120.0	93.1	105.1	158.1	198.1
390	68.0	68.0	120.0	96.9	108.5	159.4	199.4
400	68.0	68.0	120.0	100.5	111.6	160.7	200.7
410	68.0	68.0	120.0	103.9	114.7	162.0	202.0
420	68.0	68.0	120.0	107.2	117.6	163.2	203.2
430	68.0	68.0	120.0	110.3	120.4	164.4	204.4
440	70.1	68.0	120.0	113.2	123.1	165.6	205.6
450	74.1	68.0	120.0	116.1	125.6	166.7	206.7
460	77.8	68.0	120.0	118.8	128.1	167.8	207.8
470	81.4	68.0	120.0	121.5	130.5	168.9	208.9
480	84.8	68.0	120.0	124.0	132.9	170.0	210.0
490	88.0	68.0	120.0	126.5	135.1	171.1	211.1
500	91.1	68.0	120.0	128.8	137.3	172.1	212.1
510	94.0	72.2	120.0	131.1	139.4	173.1	213.1

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
520	96.9	76.2	120.0	133.3	141.4	174.1	214.1
530	99.6	80.0	120.0	135.5	143.4	175.1	215.1
540	102.2	83.6	120.0	137.6	145.3	176.1	216.1
550	104.7	87.0	120.0	139.6	147.2	177.1	217.1
560	107.2	90.3	120.0	141.5	149.1	178.0	218.0
570	109.5	93.4	120.0	143.5	150.8	178.9	218.9
580	111.8	96.3	120.0	145.3	152.6	179.8	219.8
590	114.0	99.2	120.0	147.1	154.3	180.7	220.7
600	116.1	101.9	120.0	148.9	155.9	181.6	221.6
610	118.2	104.5	120.0	150.6	157.5	182.5	222.5
620	120.2	107.1	120.0	152.3	159.1	183.3	223.3
630	122.1	109.5	120.0	153.9	160.7	184.2	224.2
640	124.0	111.9	120.0	155.5	162.2	185.0	225.0
650	125.9	114.2	120.0	157.1	163.6	185.8	225.8
660	127.7	116.4	120.0	158.6	165.1	186.6	226.6
670	129.4	118.5	120.0	160.1	166.5	187.4	227.4
680	131.1	120.6	120.0	161.6	167.9	187.9	227.9
690	132.8	122.6	120.0	163.0	169.2	188.3	228.3
700	134.4	124.6	120.0	164.4	170.6	188.8	228.8
710	136.0	126.5	120.0	165.8	171.9	189.2	229.2
720	137.6	128.3	120.0	167.1	173.2	189.6	229.6
730	139.1	130.1	120.0	168.4	174.4	190.0	230.0
740	140.6	131.9	120.0	169.7	175.7	190.4	230.4
750	142.0	133.6	120.0	171.0	176.9	190.8	230.8
760	143.5	135.3	120.0	172.3	178.1	191.2	231.2
770	144.8	136.9	120.0	173.5	179.3	191.6	231.6
780	146.2	138.5	120.0	174.7	180.4	192.0	232.0

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
790	147.6	140.1	120.0	175.9	181.5	192.4	232.4
800	148.9	141.6	120.0	177.0	182.7	192.7	232.7
810	150.2	143.1	120.0	178.2	183.8	193.1	233.1
820	151.4	144.5	120.0	179.3	184.8	193.5	233.5
830	152.7	146.0	120.8	180.4	185.9	193.9	233.9
840	153.9	147.4	122.1	181.5	187.0	194.3	234.3
850	155.1	148.7	123.3	182.6	188.0	194.7	234.7
860	156.3	150.1	124.6	183.6	189.0	195.0	235.0
870	157.5	151.4	125.8	184.7	190.0	195.4	235.4
880	158.6	152.7	126.9	185.7	191.0	195.8	235.8
890	159.7	154.0	128.1	186.7	192.0	196.1	236.1
900	160.8	155.2	129.3	187.7	192.9	196.5	236.5
910	161.9	156.5	130.4	188.7	193.9	196.9	236.9
920	163.0	157.7	131.5	189.7	194.8	197.2	237.2
930	164.0	158.8	132.6	190.6	195.8	197.6	237.6
940	165.1	160.0	133.7	191.6	196.7	198.0	238.0
950	166.1	161.2	134.7	192.5	197.6	198.3	238.3
960	167.1	162.3	135.8	193.4	198.5	198.7	238.7
970	168.1	163.4	136.8	194.3	199.3	199.0	239.3
980	169.1	164.5	137.8	195.2	200.2	199.4	240.2
990	170.0	165.6	138.8	196.1	201.0	199.7	241.0
1000	171.0	166.6	139.8	197.0	201.9	200.1	241.9
1010	171.9	167.7	140.7	197.8	202.7	200.4	242.7
1020	172.9	168.7	141.7	198.7	203.5	200.8	243.5
1030	173.8	169.7	142.6	199.5	204.4	201.1	244.4
1040	174.7	170.7	143.6	200.4	205.2	201.4	245.2
1050	175.6	171.7	144.5	201.2	206.0	201.8	246.0

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1060	176.5	172.6	145.4	202.0	206.7	202.1	246.7
1070	177.3	173.6	146.3	202.8	207.5	202.5	247.5
1080	178.2	174.5	147.2	203.6	208.3	202.8	248.3
1090	179.0	175.5	148.0	204.4	209.1	203.1	249.1
1100	179.9	176.4	148.9	205.1	209.8	203.5	249.8
1110	180.7	177.3	149.7	205.9	210.6	203.8	250.6
1120	181.5	178.2	150.6	206.7	211.3	204.1	251.3
1130	182.3	179.1	151.4	207.4	212.0	204.4	252.0
1140	183.1	179.9	152.2	208.1	212.7	204.8	252.7
1150	183.9	180.8	153.0	208.9	213.4	205.1	253.4
1160	184.7	181.6	153.8	209.6	214.2	205.4	254.2
1170	185.5	182.5	154.6	210.3	214.9	205.7	254.9
1180	186.2	183.3	155.4	211.0	215.5	206.0	255.5
1190	187.0	184.1	156.2	211.7	216.2	206.4	256.2
1200	187.7	184.9	156.9	212.4	216.9	206.7	256.9
1210	188.5	185.7	157.7	213.1	217.6	207.0	257.6
1220	189.2	186.5	158.4	213.8	218.2	207.3	258.2
1230	189.9	187.3	159.2	214.5	218.9	207.6	258.9
1240	190.6	188.1	159.9	215.1	219.6	207.9	259.6
1250	191.3	188.8	160.6	215.8	220.2	208.2	260.2
1260	192.0	189.6	161.4	216.5	220.8	208.5	260.8
1270	192.7	190.3	162.1	217.1	221.5	208.8	261.5
1280	193.4	191.1	162.8	217.8	222.1	209.1	262.1
1290	194.1	191.8	163.5	218.4	222.7	209.4	262.7
1300	194.8	192.5	164.1	219.0	223.3	209.7	263.3
1310	195.4	193.3	164.8	219.6	224.0	210.0	264.0
1320	196.1	194.0	165.5	220.3	224.6	210.3	264.6

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1330	196.8	194.7	166.2	220.9	225.2	210.6	265.2
1340	197.4	195.4	166.8	221.5	225.8	210.9	265.8
1350	198.1	196.1	167.5	222.1	226.4	211.2	266.4
1360	198.7	196.7	168.1	222.7	226.9	211.5	266.9
1370	199.3	197.4	168.8	223.3	227.5	211.8	267.5
1380	199.9	198.1	169.4	223.9	228.1	212.1	268.1
1390	200.6	198.7	170.0	224.5	228.7	212.4	268.7
1400	201.2	199.4	170.7	225.0	229.2	212.7	269.2

5. REFERENCES

[1] "Fracture Toughness Requirements", Appendix G to Part 50 of Title 10 of the Code of Federal Regulations, December 1995.

[2] Carey, R. G., "Extended Power Uprate Evaluation Task Report for Edwin I. Hatch Plant Units 1 & 2, Revised Impact on Vessel Fracture Toughness," GE-NE-A13-00402-9, March 1998.

[3] "Radiation Embrittlement of Reactor Vessel Materials", USNRC Regulatory Guide 1.99, Revision 2, May 1988

[4] H. S. Mehta, T. A. Caine, and S. E. Plaxton, "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 through BWR/6 Vessels, Rev. 1," GENE, San Jose, CA, February, 1994, (NEDO-32205-A).

[5] "PVRC Recommendations on Toughness Requirements for Ferritic Materials", Welding Research Council Bulletin 175, August 1972.

[6] Frew, B. D., "Plant Hatch Unit 1 RPV Surveillance Materials Testing and Analysis", GE-NE-B1100691-01R1, March 1997.

[7] Caine, T. A. "E.I. Hatch Nuclear Power Station Unit 2 Vessel Surveillance Materials Testing and Fracture Toughness Analysis,", SASR 90-104, May 1991.

[8] Protection Against Non-Ductile Failure", Appendix G to Section XI of the 1989 ASME Boiler & Pressure Vessel Code.

[9] Design Stress Intensity Values, Allowable Stresses, Material Properties, and Design Fatigue Curves", Section III Appendix I of the 1989 ASME Boiler and Pressure Vessel Code.

APPENDIX A

HATCH UNIT 1 P-T CURVES

VALID TO 36 EFPY

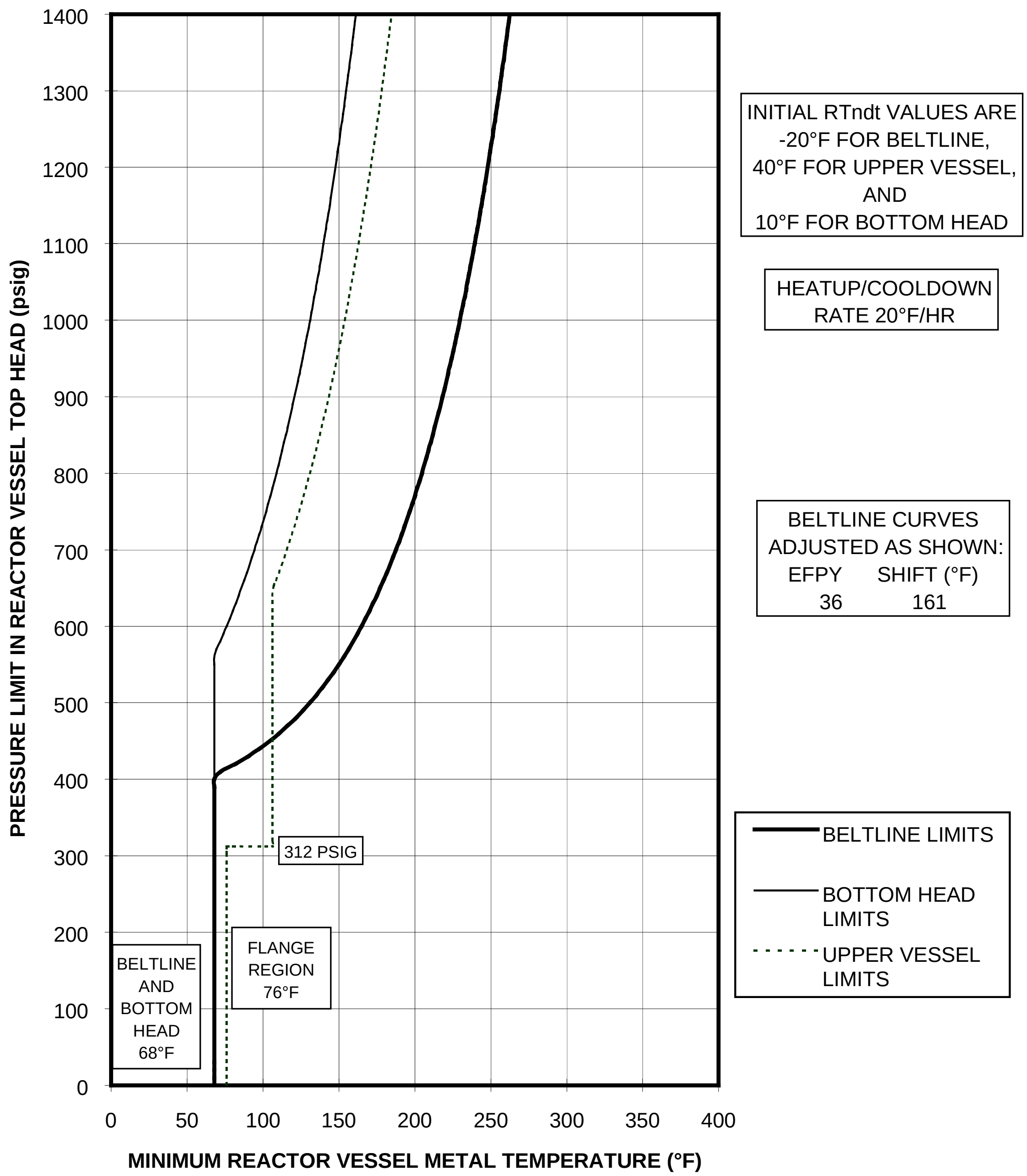

Figure A-1: P-T Curve for Unit 1 (Curve A)

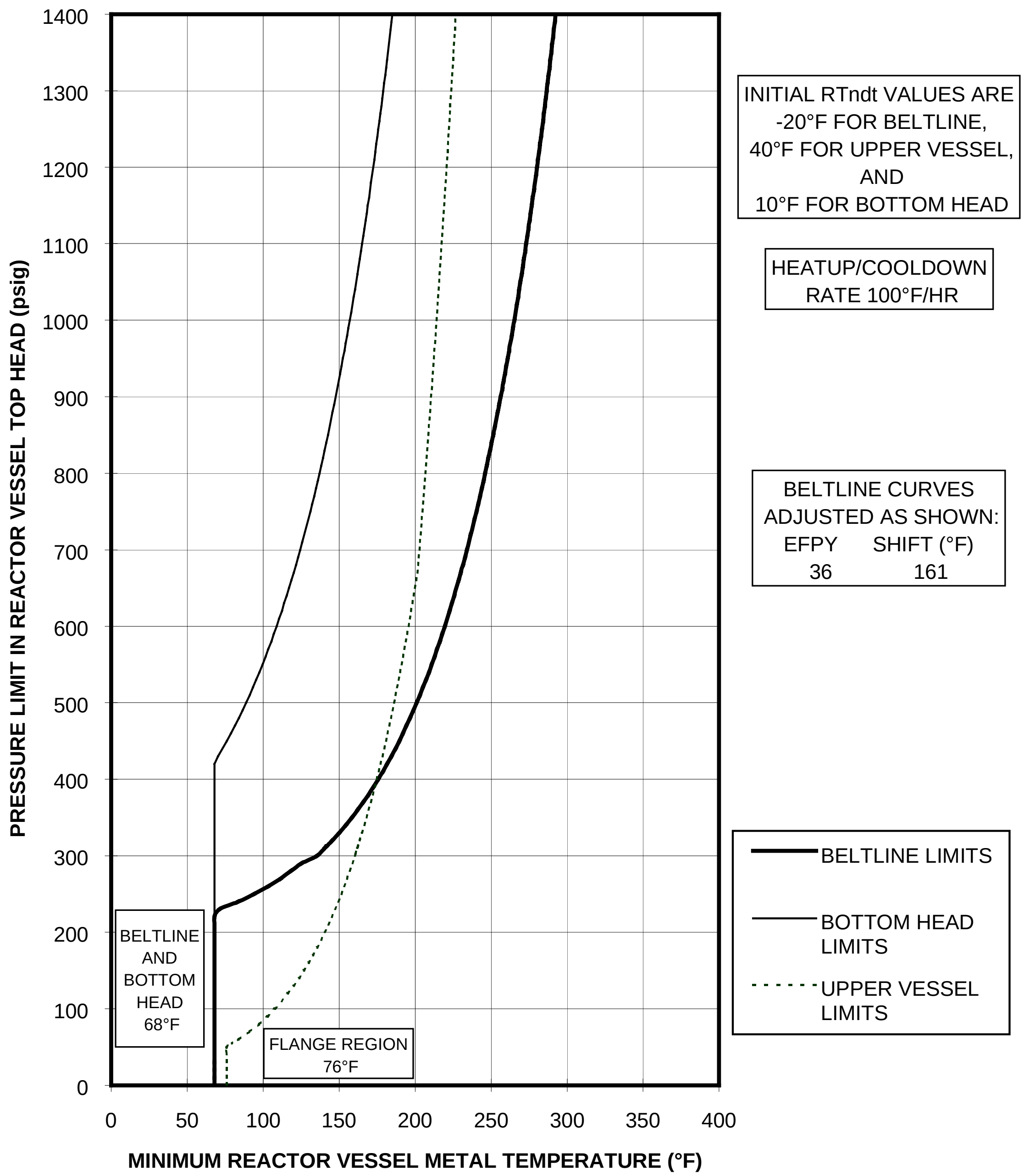

Figure A-2: P-T Curve for Unit 1 (Curve B)

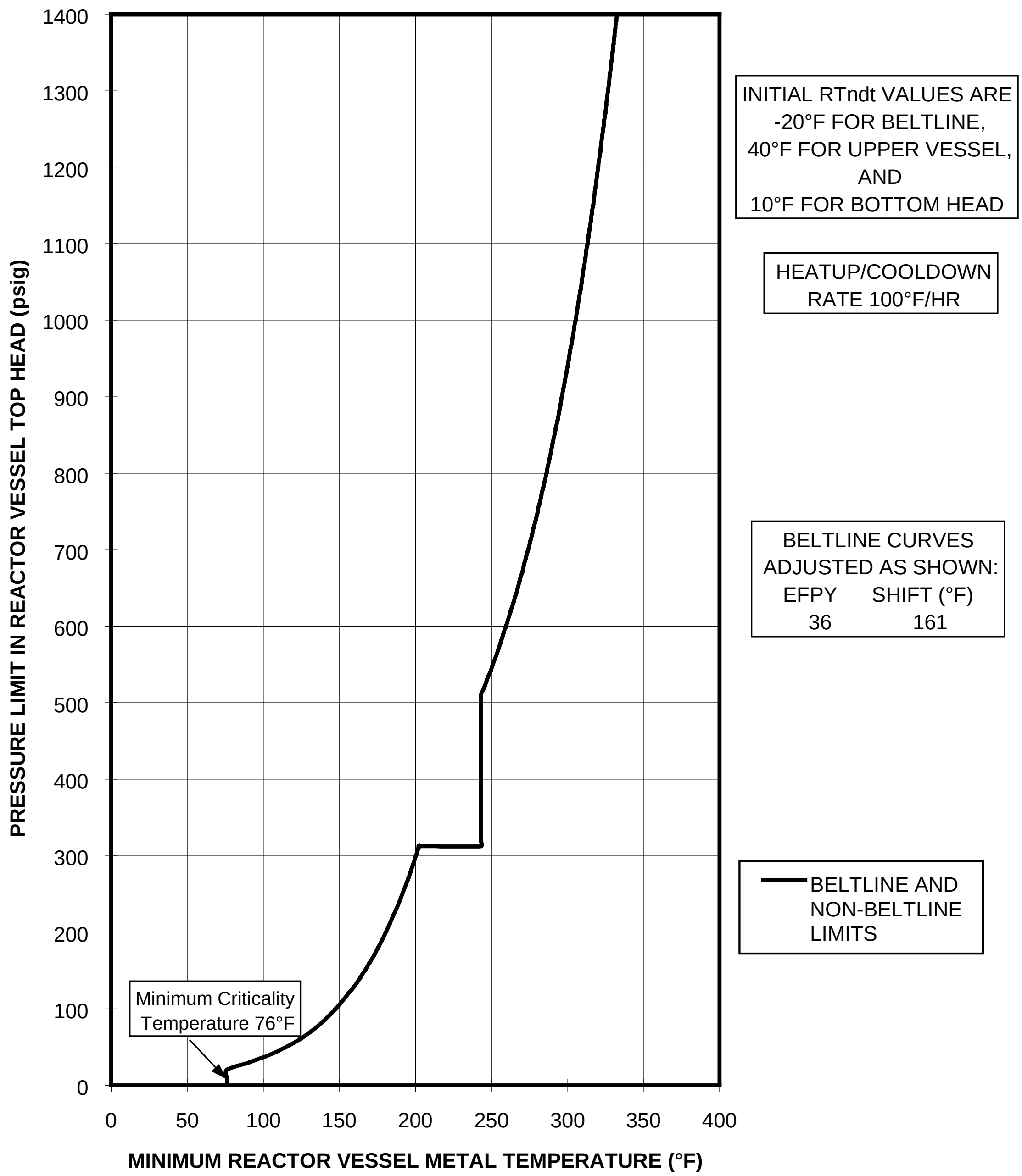

Figure A-3: P-T Curve for Unit 1 (Curve C)

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	68.0	145.2	185.2
230	68.0	68.0	76.0	68.0	71.2	147.4	187.4
240	68.0	68.0	76.0	68.0	83.6	149.4	189.4
250	68.0	68.0	76.0	68.0	94.1	151.4	191.4
260	68.0	68.0	76.0	68.0	103.2	153.3	193.3

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
270	68.0	68.0	76.0	68.0	111.3	155.1	195.1
280	68.0	68.0	76.0	68.0	118.5	157.0	197.0
290	68.0	68.0	76.0	68.0	125.0	158.7	198.7
300	68.0	68.0	76.0	68.0	135.3	160.3	200.3
310	68.0	68.0	76.0	68.0	140.6	162.0	202.0
312.5	68.0	68.0	76.0	68.0	141.9	162.3	202.3
312.5	68.0	68.0	106.0	68.0	141.9	162.3	243.0
320	68.0	68.0	106.0	68.0	145.5	163.5	243.0
330	68.0	68.0	106.0	68.0	150.1	165.1	243.0
340	68.0	68.0	106.0	68.0	154.4	166.6	243.0
350	68.0	68.0	106.0	68.0	158.5	168.0	243.0
360	68.0	68.0	106.0	68.0	162.3	169.4	243.0
370	68.0	68.0	106.0	68.0	165.9	170.8	243.0
380	68.0	68.0	106.0	68.0	169.3	172.1	243.0
390	68.0	68.0	106.0	68.0	172.6	173.4	243.0
400	68.0	68.0	106.0	68.0	175.8	174.7	243.0
410	68.0	72.2	106.0	68.0	178.7	176.0	243.0
420	68.0	81.8	106.0	68.0	181.6	177.2	243.0
430	68.0	90.3	106.0	70.3	184.4	178.4	243.0
440	68.0	97.8	106.0	73.2	187.0	179.6	243.0
450	68.0	104.5	106.0	76.1	189.6	180.7	243.0
460	68.0	110.7	106.0	78.8	192.0	181.8	243.0
470	68.0	116.3	106.0	81.5	194.4	182.9	243.0
480	68.0	121.6	106.0	84.0	196.7	184.0	243.0
490	68.0	126.4	106.0	86.5	198.9	185.1	243.0
500	68.0	130.9	106.0	88.8	201.1	186.1	243.0
510	68.0	135.2	106.0	91.1	203.1	187.1	243.1

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
520	68.0	139.2	106.0	93.3	205.2	188.1	245.2
530	68.0	143.0	106.0	95.5	207.1	189.1	247.1
540	68.0	146.6	106.0	97.6	209.1	190.1	249.1
550	68.0	150.0	106.0	99.6	210.9	191.1	250.9
560	68.0	153.3	106.0	101.5	212.7	192.0	252.7
570	69.5	156.4	106.0	103.5	214.5	192.9	254.5
580	71.8	159.3	106.0	105.3	216.2	193.8	256.2
590	74.0	162.2	106.0	107.1	217.9	194.7	257.9
600	76.1	164.9	106.0	108.9	219.5	195.6	259.5
610	78.2	167.6	106.0	110.6	221.1	196.5	261.1
620	80.2	170.1	106.0	112.3	222.7	197.3	262.7
630	82.1	172.5	106.0	113.9	224.2	198.2	264.2
640	84.0	174.9	106.0	115.5	225.7	199.0	265.7
650	85.9	177.2	106.7	117.1	227.2	199.8	267.2
660	87.7	179.4	108.6	118.6	228.6	200.6	268.6
670	89.4	181.5	110.4	120.1	230.0	201.4	270.0
680	91.1	183.6	112.2	121.6	231.4	201.9	271.4
690	92.8	185.6	114.0	123.0	232.8	202.3	272.8
700	94.4	187.6	115.7	124.4	234.1	202.8	274.1
710	96.0	189.5	117.4	125.8	235.4	203.2	275.4
720	97.6	191.4	119.0	127.1	236.7	203.6	276.7
730	99.1	193.2	120.6	128.4	237.9	204.0	277.9
740	100.6	194.9	122.2	129.7	239.2	204.4	279.2
750	102.0	196.6	123.7	131.0	240.4	204.8	280.4
760	103.5	198.3	125.2	132.3	241.5	205.2	281.5
770	104.8	199.9	126.7	133.5	242.7	205.6	282.7
780	106.2	201.5	128.1	134.7	243.9	206.0	283.9

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
790	107.6	203.1	129.5	135.9	245.0	206.4	285.0
800	108.9	204.6	130.9	137.0	246.1	206.7	286.1
810	110.2	206.1	132.2	138.2	247.2	207.1	287.2
820	111.4	207.6	133.5	139.3	248.3	207.5	288.3
830	112.7	209.0	134.8	140.4	249.3	207.9	289.3
840	113.9	210.4	136.1	141.5	250.4	208.3	290.4
850	115.1	211.8	137.3	142.6	251.4	208.7	291.4
860	116.3	213.1	138.6	143.6	252.4	209.0	292.4
870	117.5	214.5	139.8	144.7	253.4	209.4	293.4
880	118.6	215.7	140.9	145.7	254.4	209.8	294.4
890	119.7	217.0	142.1	146.7	255.4	210.1	295.4
900	120.8	218.3	143.3	147.7	256.3	210.5	296.3
910	121.9	219.5	144.4	148.7	257.3	210.9	297.3
920	123.0	220.7	145.5	149.7	258.2	211.2	298.2
930	124.0	221.9	146.6	150.6	259.1	211.6	299.1
940	125.1	223.1	147.7	151.6	260.0	212.0	300.0
950	126.1	224.2	148.7	152.5	260.9	212.3	300.9
960	127.1	225.3	149.8	153.4	261.8	212.7	301.8
970	128.1	226.4	150.8	154.3	262.7	213.0	302.7
980	129.1	227.5	151.8	155.2	263.5	213.4	303.5
990	130.0	228.6	152.8	156.1	264.4	213.7	304.4
1000	131.0	229.7	153.8	157.0	265.2	214.1	305.2
1010	131.9	230.7	154.7	157.8	266.1	214.4	306.1
1020	132.9	231.7	155.7	158.7	266.9	214.8	306.9
1030	133.8	232.7	156.6	159.5	267.7	215.1	307.7
1040	134.7	233.7	157.6	160.4	268.5	215.4	308.5
1050	135.6	234.7	158.5	161.2	269.3	215.8	309.3

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
1060	136.5	235.7	159.4	162.0	270.1	216.1	310.1
1070	137.3	236.6	160.3	162.8	270.9	216.5	310.9
1080	138.2	237.6	161.2	163.6	271.6	216.8	311.6
1090	139.0	238.5	162.0	164.4	272.4	217.1	312.4
1100	139.9	239.4	162.9	165.1	273.1	217.5	313.1
1110	140.7	240.3	163.7	165.9	273.9	217.8	313.9
1120	141.5	241.2	164.6	166.7	274.6	218.1	314.6
1130	142.3	242.1	165.4	167.4	275.3	218.4	315.3
1140	143.1	243.0	166.2	168.1	276.0	218.8	316.0
1150	143.9	243.8	167.0	168.9	276.8	219.1	316.8
1160	144.7	244.7	167.8	169.6	277.5	219.4	317.5
1170	145.5	245.5	168.6	170.3	278.2	219.7	318.2
1180	146.2	246.4	169.4	171.0	278.8	220.0	318.8
1190	147.0	247.2	170.2	171.7	279.5	220.4	319.5
1200	147.7	248.0	170.9	172.4	280.2	220.7	320.2
1210	148.5	248.8	171.7	173.1	280.9	221.0	320.9
1220	149.2	249.6	172.4	173.8	281.5	221.3	321.5
1230	149.9	250.4	173.2	174.5	282.2	221.6	322.2
1240	150.6	251.1	173.9	175.1	282.8	221.9	322.8
1250	151.3	251.9	174.6	175.8	283.5	222.2	323.5
1260	152.0	252.6	175.4	176.5	284.1	222.5	324.1
1270	152.7	253.4	176.1	177.1	284.8	222.8	324.8
1280	153.4	254.1	176.8	177.8	285.4	223.1	325.4
1290	154.1	254.9	177.5	178.4	286.0	223.4	326.0
1300	154.8	255.6	178.1	179.0	286.6	223.7	326.6
1310	155.4	256.3	178.8	179.6	287.2	224.0	327.2
1320	156.1	257.0	179.5	180.3	287.8	224.3	327.8

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
1330	156.8	257.7	180.2	180.9	288.4	224.6	328.4
1340	157.4	258.4	180.8	181.5	289.0	224.9	329.0
1350	158.1	259.1	181.5	182.1	289.6	225.2	329.6
1360	158.7	259.8	182.1	182.7	290.2	225.5	330.2
1370	159.3	260.5	182.8	183.3	290.8	225.8	330.8
1380	159.9	261.1	183.4	183.9	291.4	226.1	331.4
1390	160.6	261.8	184.0	184.5	291.9	226.4	331.9
1400	161.2	262.4	184.7	185.0	292.5	226.7	332.5

APPENDIX B

HATCH UNIT 1 P-T CURVES

VALID TO 40 EFPY

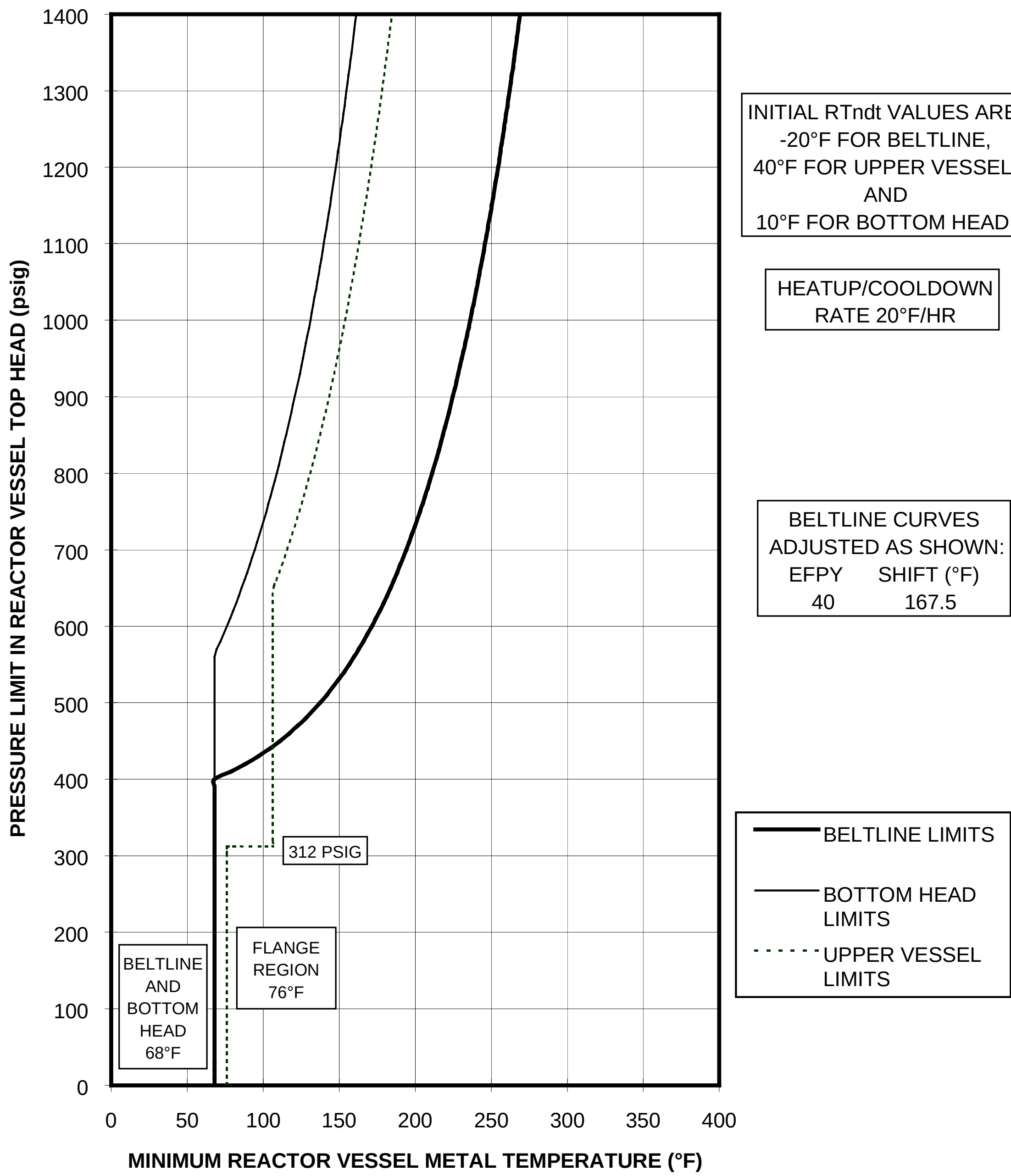

Figure B-1: P-T Curve for Unit 1 (Curve A)

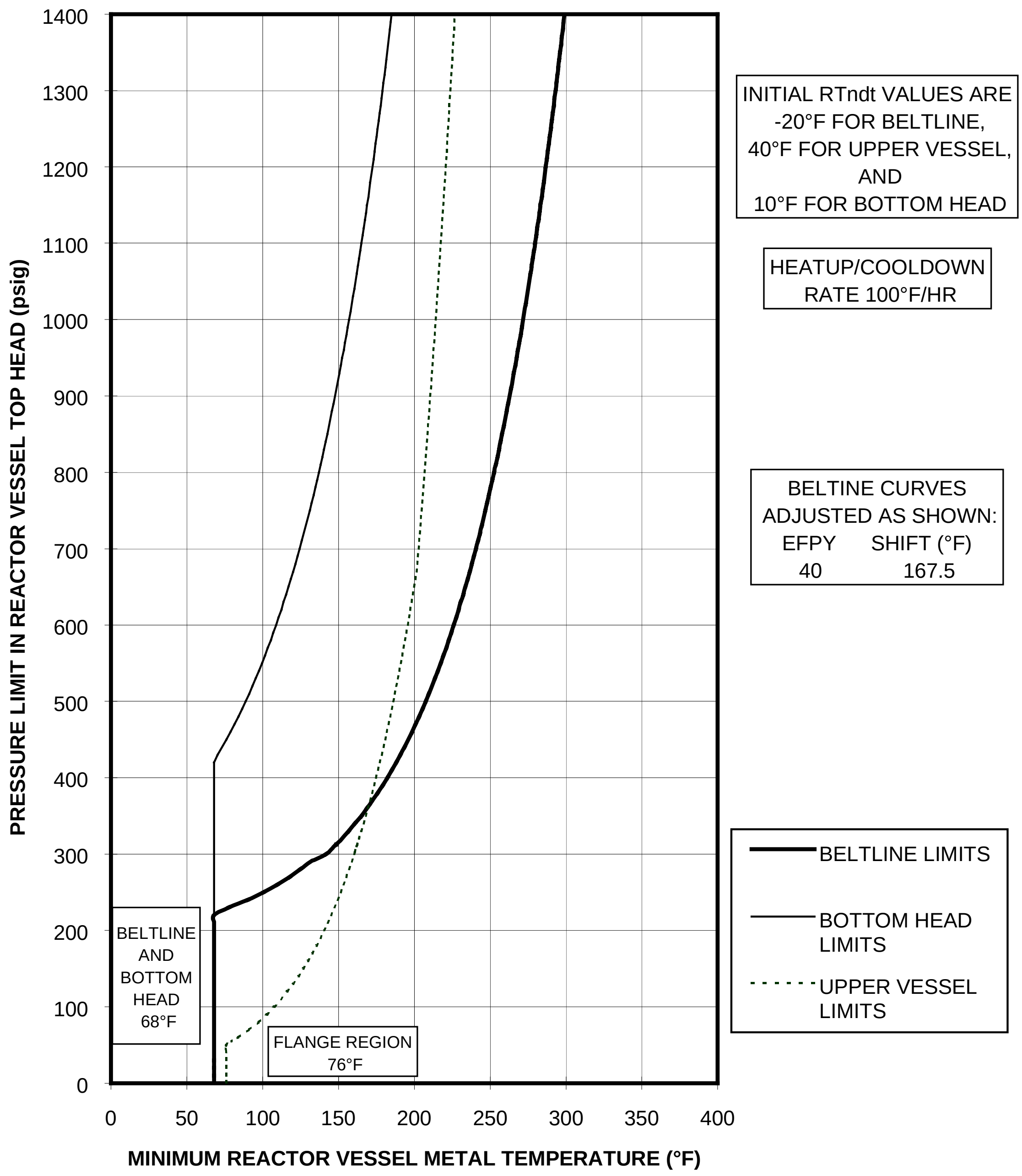

Figure B-2: P-T Curve for Unit 1 (Curve B)

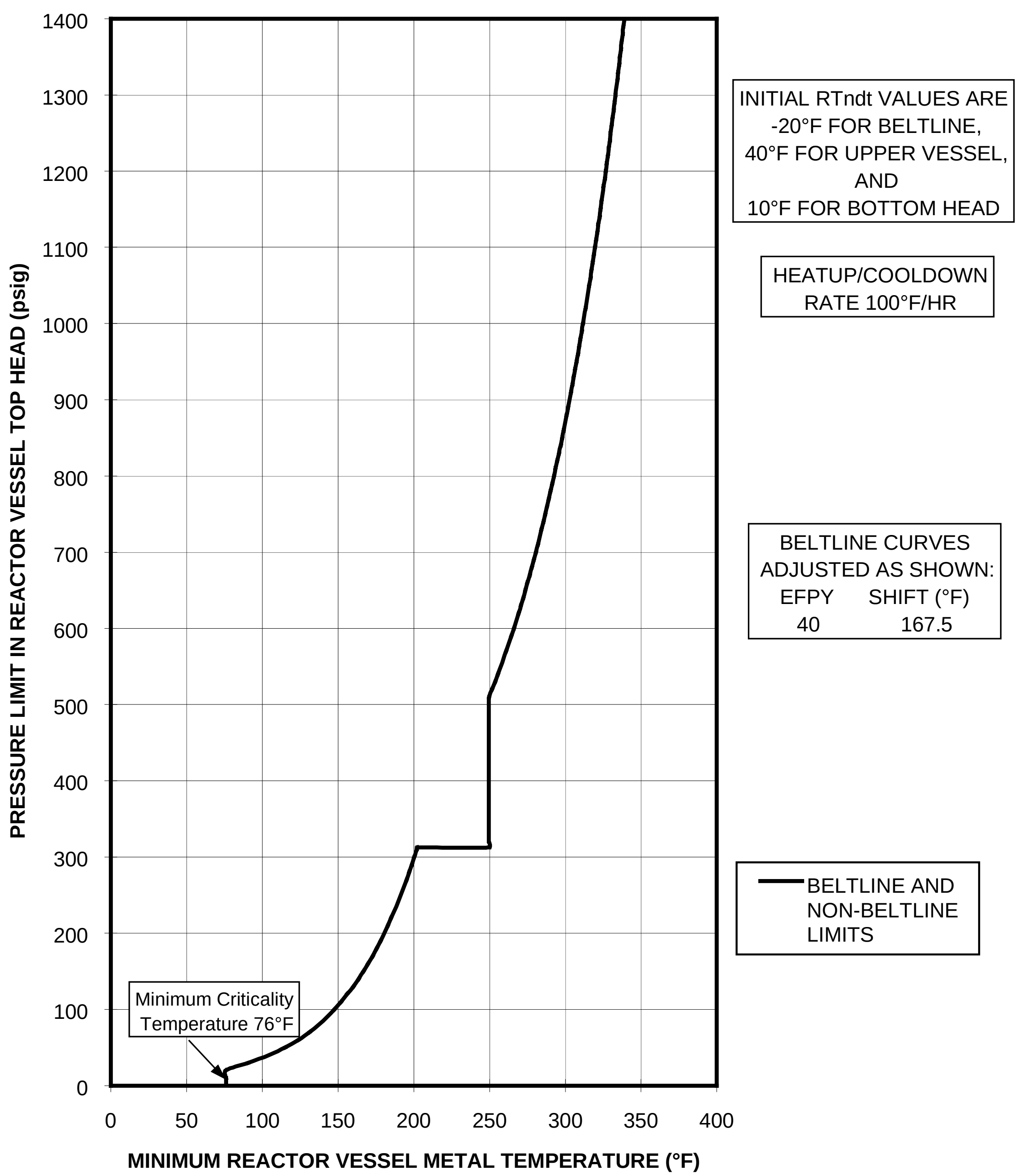

Figure B-3: P-T Curve for Unit 1 (Curve C)

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	68.0	145.2	185.2
230	68.0	68.0	76.0	68.0	77.7	147.4	187.4
240	68.0	68.0	76.0	68.0	90.1	149.4	189.4
250	68.0	68.0	76.0	68.0	100.6	151.4	191.4

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
260	68.0	68.0	76.0	68.0	109.7	153.3	193.3
270	68.0	68.0	76.0	68.0	117.8	155.1	195.1
280	68.0	68.0	76.0	68.0	125.0	157.0	197.0
290	68.0	68.0	76.0	68.0	131.5	158.7	198.7
300	68.0	68.0	76.0	68.0	141.8	160.3	200.3
310	68.0	68.0	76.0	68.0	147.1	162.0	202.0
312.5	68.0	68.0	76.0	68.0	148.4	162.3	202.3
312.5	68.0	68.0	106.0	68.0	148.4	162.3	249.5
320	68.0	68.0	106.0	68.0	152.0	163.5	249.5
330	68.0	68.0	106.0	68.0	156.6	165.1	249.5
340	68.0	68.0	106.0	68.0	160.9	166.6	249.5
350	68.0	68.0	106.0	68.0	165.0	168.0	249.5
360	68.0	68.0	106.0	68.0	168.8	169.4	249.5
370	68.0	68.0	106.0	68.0	172.4	170.8	249.5
380	68.0	68.0	106.0	68.0	175.8	172.1	249.5
390	68.0	68.0	106.0	68.0	179.1	173.4	249.5
400	68.0	68.0	106.0	68.0	182.3	174.7	249.5
410	68.0	78.7	106.0	68.0	185.2	176.0	249.5
420	68.0	88.3	106.0	68.0	188.1	177.2	249.5
430	68.0	96.8	106.0	70.3	190.9	178.4	249.5
440	68.0	104.3	106.0	73.2	193.5	179.6	249.5
450	68.0	111.0	106.0	76.1	196.1	180.7	249.5
460	68.0	117.2	106.0	78.8	198.5	181.8	249.5
470	68.0	122.8	106.0	81.5	200.9	182.9	249.5
480	68.0	128.1	106.0	84.0	203.2	184.0	249.5
490	68.0	132.9	106.0	86.5	205.4	185.1	249.5
500	68.0	137.4	106.0	88.8	207.6	186.1	249.5

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
510	68.0	141.7	106.0	91.1	209.6	187.1	249.6
520	68.0	145.7	106.0	93.3	211.7	188.1	251.7
530	68.0	149.5	106.0	95.5	213.6	189.1	253.6
540	68.0	153.1	106.0	97.6	215.6	190.1	255.6
550	68.0	156.5	106.0	99.6	217.4	191.1	257.4
560	68.0	159.8	106.0	101.5	219.2	192.0	259.2
570	69.5	162.9	106.0	103.5	221.0	192.9	261.0
580	71.8	165.8	106.0	105.3	222.7	193.8	262.7
590	74.0	168.7	106.0	107.1	224.4	194.7	264.4
600	76.1	171.4	106.0	108.9	226.0	195.6	266.0
610	78.2	174.1	106.0	110.6	227.6	196.5	267.6
620	80.2	176.6	106.0	112.3	229.2	197.3	269.2
630	82.1	179.0	106.0	113.9	230.7	198.2	270.7
640	84.0	181.4	106.0	115.5	232.2	199.0	272.2
650	85.9	183.7	106.7	117.1	233.7	199.8	273.7
660	87.7	185.9	108.6	118.6	235.1	200.6	275.1
670	89.4	188.0	110.4	120.1	236.5	201.4	276.5
680	91.1	190.1	112.2	121.6	237.9	201.9	277.9
690	92.8	192.1	114.0	123.0	239.3	202.3	279.3
700	94.4	194.1	115.7	124.4	240.6	202.8	280.6
710	96.0	196.0	117.4	125.8	241.9	203.2	281.9
720	97.6	197.9	119.0	127.1	243.2	203.6	283.2
730	99.1	199.7	120.6	128.4	244.4	204.0	284.4
740	100.6	201.4	122.2	129.7	245.7	204.4	285.7
750	102.0	203.1	123.7	131.0	246.9	204.8	286.9
760	103.5	204.8	125.2	132.3	248.0	205.2	288.0
770	104.8	206.4	126.7	133.5	249.2	205.6	289.2

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
780	106.2	208.0	128.1	134.7	250.4	206.0	290.4
790	107.6	209.6	129.5	135.9	251.5	206.4	291.5
800	108.9	211.1	130.9	137.0	252.6	206.7	292.6
810	110.2	212.6	132.2	138.2	253.7	207.1	293.7
820	111.4	214.1	133.5	139.3	254.8	207.5	294.8
830	112.7	215.5	134.8	140.4	255.8	207.9	295.8
840	113.9	216.9	136.1	141.5	256.9	208.3	296.9
850	115.1	218.3	137.3	142.6	257.9	208.7	297.9
860	116.3	219.6	138.6	143.6	258.9	209.0	298.9
870	117.5	221.0	139.8	144.7	259.9	209.4	299.9
880	118.6	222.2	140.9	145.7	260.9	209.8	300.9
890	119.7	223.5	142.1	146.7	261.9	210.1	301.9
900	120.8	224.8	143.3	147.7	262.8	210.5	302.8
910	121.9	226.0	144.4	148.7	263.8	210.9	303.8
920	123.0	227.2	145.5	149.7	264.7	211.2	304.7
930	124.0	228.4	146.6	150.6	265.6	211.6	305.6
940	125.1	229.6	147.7	151.6	266.5	212.0	306.5
950	126.1	230.7	148.7	152.5	267.4	212.3	307.4
960	127.1	231.8	149.8	153.4	268.3	212.7	308.3
970	128.1	232.9	150.8	154.3	269.2	213.0	309.2
980	129.1	234.0	151.8	155.2	270.0	213.4	310.0
990	130.0	235.1	152.8	156.1	270.9	213.7	310.9
1000	131.0	236.2	153.8	157.0	271.7	214.1	311.7
1010	131.9	237.2	154.7	157.8	272.6	214.4	312.6
1020	132.9	238.2	155.7	158.7	273.4	214.8	313.4
1030	133.8	239.2	156.6	159.5	274.2	215.1	314.2
1040	134.7	240.2	157.6	160.4	275.0	215.4	315.0

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
1050	135.6	241.2	158.5	161.2	275.8	215.8	315.8
1060	136.5	242.2	159.4	162.0	276.6	216.1	316.6
1070	137.3	243.1	160.3	162.8	277.4	216.5	317.4
1080	138.2	244.1	161.2	163.6	278.1	216.8	318.1
1090	139.0	245.0	162.0	164.4	278.9	217.1	318.9
1100	139.9	245.9	162.9	165.1	279.6	217.5	319.6
1110	140.7	246.8	163.7	165.9	280.4	217.8	320.4
1120	141.5	247.7	164.6	166.7	281.1	218.1	321.1
1130	142.3	248.6	165.4	167.4	281.8	218.4	321.8
1140	143.1	249.5	166.2	168.1	282.5	218.8	322.5
1150	143.9	250.3	167.0	168.9	283.3	219.1	323.3
1160	144.7	251.2	167.8	169.6	284.0	219.4	324.0
1170	145.5	252.0	168.6	170.3	284.7	219.7	324.7
1180	146.2	252.9	169.4	171.0	285.3	220.0	325.3
1190	147.0	253.7	170.2	171.7	286.0	220.4	326.0
1200	147.7	254.5	170.9	172.4	286.7	220.7	326.7
1210	148.5	255.3	171.7	173.1	287.4	221.0	327.4
1220	149.2	256.1	172.4	173.8	288.0	221.3	328.0
1230	149.9	256.9	173.2	174.5	288.7	221.6	328.7
1240	150.6	257.6	173.9	175.1	289.3	221.9	329.3
1250	151.3	258.4	174.6	175.8	290.0	222.2	330.0
1260	152.0	259.1	175.4	176.5	290.6	222.5	330.6
1270	152.7	259.9	176.1	177.1	291.3	222.8	331.3
1280	153.4	260.6	176.8	177.8	291.9	223.1	331.9
1290	154.1	261.4	177.5	178.4	292.5	223.4	332.5
1300	154.8	262.1	178.1	179.0	293.1	223.7	333.1
1310	155.4	262.8	178.8	179.6	293.7	224.0	333.7

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
1320	156.1	263.5	179.5	180.3	294.3	224.3	334.3
1330	156.8	264.2	180.2	180.9	294.9	224.6	334.9
1340	157.4	264.9	180.8	181.5	295.5	224.9	335.5
1350	158.1	265.6	181.5	182.1	296.1	225.2	336.1
1360	158.7	266.3	182.1	182.7	296.7	225.5	336.7
1370	159.3	267.0	182.8	183.3	297.3	225.8	337.3
1380	159.9	267.6	183.4	183.9	297.9	226.1	337.9
1390	160.6	268.3	184.0	184.5	298.4	226.4	338.4
1400	161.2	268.9	184.7	185.0	299.0	226.7	339.0

APPENDIX C

HATCH UNIT 1 P-T CURVE

VALID TO 44 EFPY

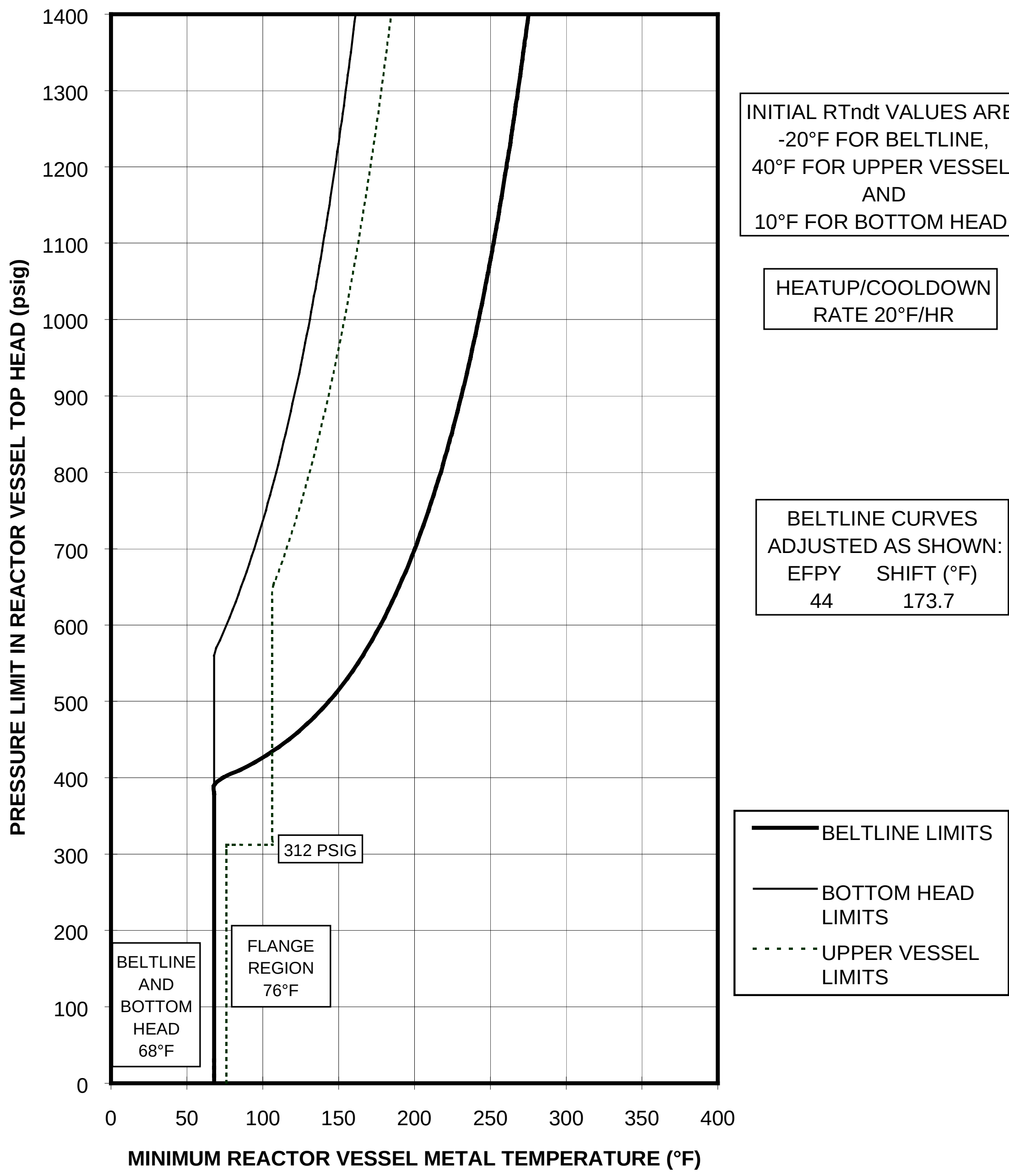

Figure C-1: P-T Curve for Unit 1 (Curve A)

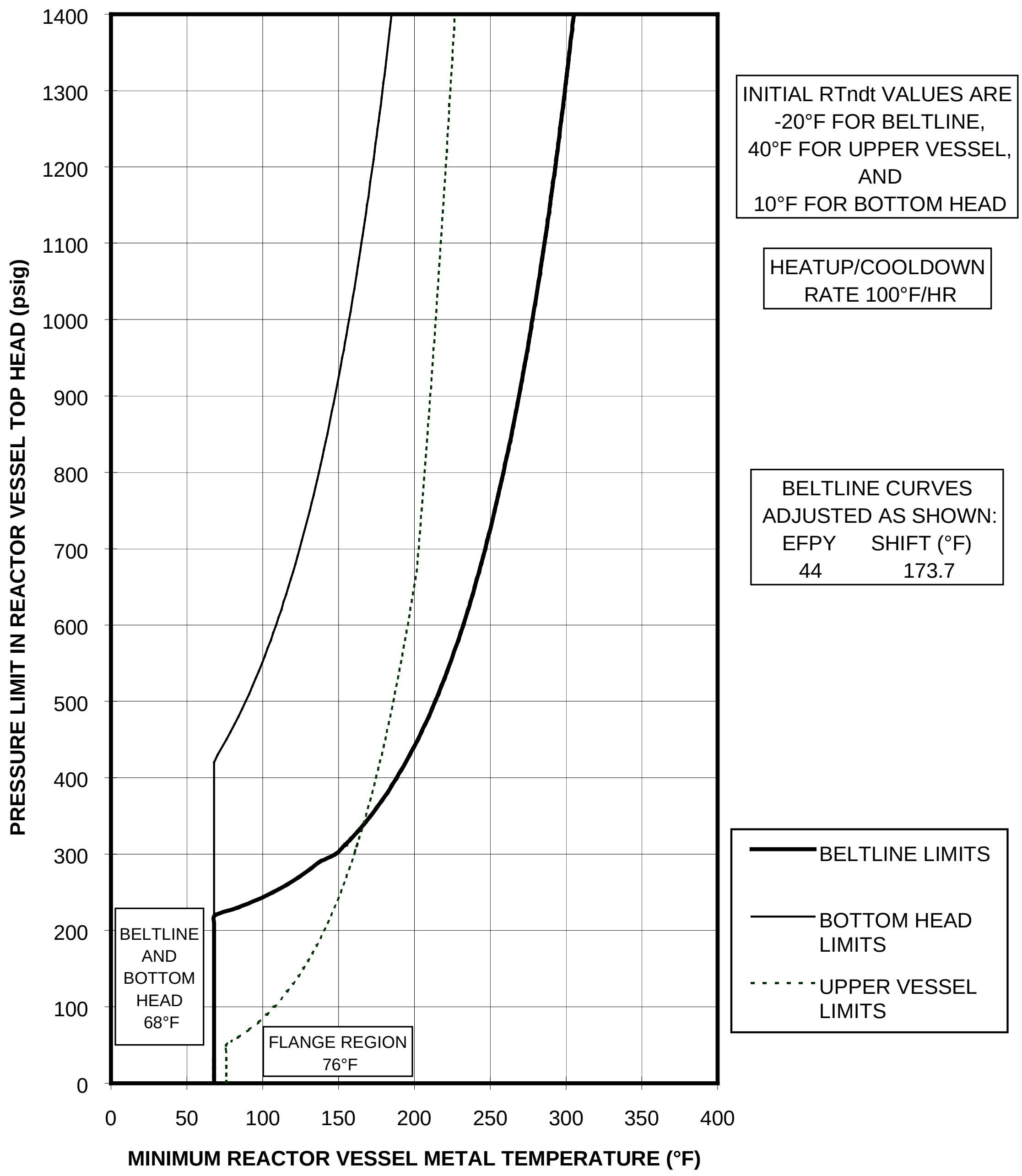

Figure C-2: P-T Curve for Unit 1 (Curve B)

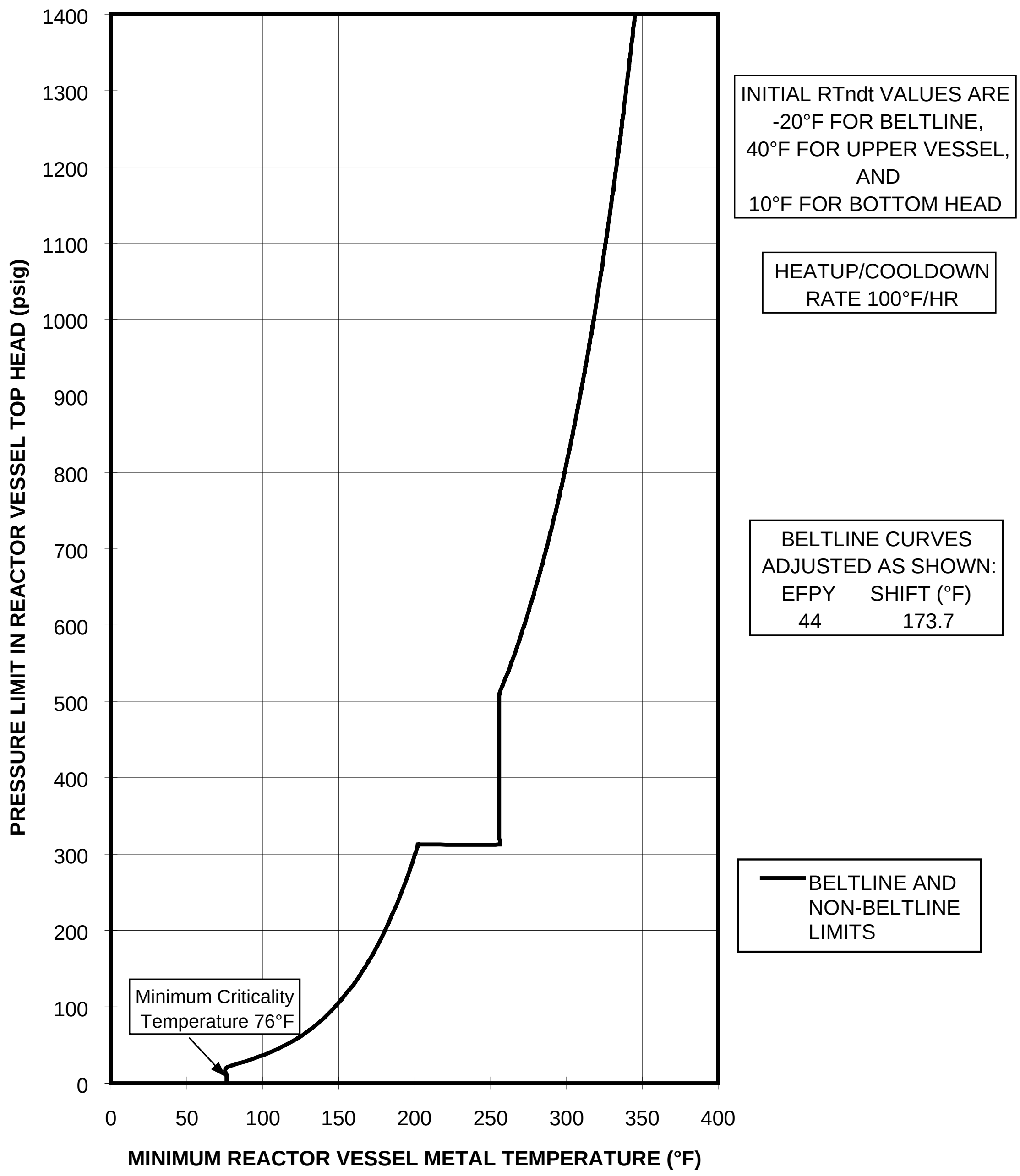

Figure C-3: P-T Curve for Unit 1 (Curve C)

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	68.7	145.2	185.2
230	68.0	68.0	76.0	68.0	83.9	147.4	187.4
240	68.0	68.0	76.0	68.0	96.3	149.4	189.4
250	68.0	68.0	76.0	68.0	106.8	151.4	191.4

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
260	68.0	68.0	76.0	68.0	115.9	153.3	193.3
270	68.0	68.0	76.0	68.0	124.0	155.1	195.1
280	68.0	68.0	76.0	68.0	131.2	157.0	197.0
290	68.0	68.0	76.0	68.0	137.7	158.7	198.7
300	68.0	68.0	76.0	68.0	148.0	160.3	200.3
310	68.0	68.0	76.0	68.0	153.3	162.0	202.0
312.5	68.0	68.0	76.0	68.0	154.6	162.3	202.3
312.5	68.0	68.0	106.0	68.0	154.6	162.3	255.7
320	68.0	68.0	106.0	68.0	158.2	163.5	255.7
330	68.0	68.0	106.0	68.0	162.8	165.1	255.7
340	68.0	68.0	106.0	68.0	167.1	166.6	255.7
350	68.0	68.0	106.0	68.0	171.2	168.0	255.7
360	68.0	68.0	106.0	68.0	175.0	169.4	255.7
370	68.0	68.0	106.0	68.0	178.6	170.8	255.7
380	68.0	68.0	106.0	68.0	182.0	172.1	255.7
390	68.0	68.0	106.0	68.0	185.3	173.4	255.7
400	68.0	73.8	106.0	68.0	188.5	174.7	255.7
410	68.0	84.9	106.0	68.0	191.4	176.0	255.7
420	68.0	94.5	106.0	68.0	194.3	177.2	255.7
430	68.0	103.0	106.0	70.3	197.1	178.4	255.7
440	68.0	110.5	106.0	73.2	199.7	179.6	255.7
450	68.0	117.2	106.0	76.1	202.3	180.7	255.7
460	68.0	123.4	106.0	78.8	204.7	181.8	255.7
470	68.0	129.0	106.0	81.5	207.1	182.9	255.7
480	68.0	134.3	106.0	84.0	209.4	184.0	255.7
490	68.0	139.1	106.0	86.5	211.6	185.1	255.7
500	68.0	143.6	106.0	88.8	213.8	186.1	255.7

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
510	68.0	147.9	106.0	91.1	215.8	187.1	255.8
520	68.0	151.9	106.0	93.3	217.9	188.1	257.9
530	68.0	155.7	106.0	95.5	219.8	189.1	259.8
540	68.0	159.3	106.0	97.6	221.8	190.1	261.8
550	68.0	162.7	106.0	99.6	223.6	191.1	263.6
560	68.0	166.0	106.0	101.5	225.4	192.0	265.4
570	69.5	169.1	106.0	103.5	227.2	192.9	267.2
580	71.8	172.0	106.0	105.3	228.9	193.8	268.9
590	74.0	174.9	106.0	107.1	230.6	194.7	270.6
600	76.1	177.6	106.0	108.9	232.2	195.6	272.2
610	78.2	180.3	106.0	110.6	233.8	196.5	273.8
620	80.2	182.8	106.0	112.3	235.4	197.3	275.4
630	82.1	185.2	106.0	113.9	236.9	198.2	276.9
640	84.0	187.6	106.0	115.5	238.4	199.0	278.4
650	85.9	189.9	106.7	117.1	239.9	199.8	279.9
660	87.7	192.1	108.6	118.6	241.3	200.6	281.3
670	89.4	194.2	110.4	120.1	242.7	201.4	282.7
680	91.1	196.3	112.2	121.6	244.1	201.9	284.1
690	92.8	198.3	114.0	123.0	245.5	202.3	285.5
700	94.4	200.3	115.7	124.4	246.8	202.8	286.8
710	96.0	202.2	117.4	125.8	248.1	203.2	288.1
720	97.6	204.1	119.0	127.1	249.4	203.6	289.4
730	99.1	205.9	120.6	128.4	250.6	204.0	290.6
740	100.6	207.6	122.2	129.7	251.9	204.4	291.9
750	102.0	209.3	123.7	131.0	253.1	204.8	293.1
760	103.5	211.0	125.2	132.3	254.2	205.2	294.2
770	104.8	212.6	126.7	133.5	255.4	205.6	295.4

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
780	106.2	214.2	128.1	134.7	256.6	206.0	296.6
790	107.6	215.8	129.5	135.9	257.7	206.4	297.7
800	108.9	217.3	130.9	137.0	258.8	206.7	298.8
810	110.2	218.8	132.2	138.2	259.9	207.1	299.9
820	111.4	220.3	133.5	139.3	261.0	207.5	301.0
830	112.7	221.7	134.8	140.4	262.0	207.9	302.0
840	113.9	223.1	136.1	141.5	263.1	208.3	303.1
850	115.1	224.5	137.3	142.6	264.1	208.7	304.1
860	116.3	225.8	138.6	143.6	265.1	209.0	305.1
870	117.5	227.2	139.8	144.7	266.1	209.4	306.1
880	118.6	228.4	140.9	145.7	267.1	209.8	307.1
890	119.7	229.7	142.1	146.7	268.1	210.1	308.1
900	120.8	231.0	143.3	147.7	269.0	210.5	309.0
910	121.9	232.2	144.4	148.7	270.0	210.9	310.0
920	123.0	233.4	145.5	149.7	270.9	211.2	310.9
930	124.0	234.6	146.6	150.6	271.8	211.6	311.8
940	125.1	235.8	147.7	151.6	272.7	212.0	312.7
950	126.1	236.9	148.7	152.5	273.6	212.3	313.6
960	127.1	238.0	149.8	153.4	274.5	212.7	314.5
970	128.1	239.1	150.8	154.3	275.4	213.0	315.4
980	129.1	240.2	151.8	155.2	276.2	213.4	316.2
990	130.0	241.3	152.8	156.1	277.1	213.7	317.1
1000	131.0	242.4	153.8	157.0	277.9	214.1	317.9
1010	131.9	243.4	154.7	157.8	278.8	214.4	318.8
1020	132.9	244.4	155.7	158.7	279.6	214.8	319.6
1030	133.8	245.4	156.6	159.5	280.4	215.1	320.4
1040	134.7	246.4	157.6	160.4	281.2	215.4	321.2

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
1050	135.6	247.4	158.5	161.2	282.0	215.8	322.0
1060	136.5	248.4	159.4	162.0	282.8	216.1	322.8
1070	137.3	249.3	160.3	162.8	283.6	216.5	323.6
1080	138.2	250.3	161.2	163.6	284.3	216.8	324.3
1090	139.0	251.2	162.0	164.4	285.1	217.1	325.1
1100	139.9	252.1	162.9	165.1	285.8	217.5	325.8
1110	140.7	253.0	163.7	165.9	286.6	217.8	326.6
1120	141.5	253.9	164.6	166.7	287.3	218.1	327.3
1130	142.3	254.8	165.4	167.4	288.0	218.4	328.0
1140	143.1	255.7	166.2	168.1	288.7	218.8	328.7
1150	143.9	256.5	167.0	168.9	289.5	219.1	329.5
1160	144.7	257.4	167.8	169.6	290.2	219.4	330.2
1170	145.5	258.2	168.6	170.3	290.9	219.7	330.9
1180	146.2	259.1	169.4	171.0	291.5	220.0	331.5
1190	147.0	259.9	170.2	171.7	292.2	220.4	332.2
1200	147.7	260.7	170.9	172.4	292.9	220.7	332.9
1210	148.5	261.5	171.7	173.1	293.6	221.0	333.6
1220	149.2	262.3	172.4	173.8	294.2	221.3	334.2
1230	149.9	263.1	173.2	174.5	294.9	221.6	334.9
1240	150.6	263.8	173.9	175.1	295.5	221.9	335.5
1250	151.3	264.6	174.6	175.8	296.2	222.2	336.2
1260	152.0	265.3	175.4	176.5	296.8	222.5	336.8
1270	152.7	266.1	176.1	177.1	297.5	222.8	337.5
1280	153.4	266.8	176.8	177.8	298.1	223.1	338.1
1290	154.1	267.6	177.5	178.4	298.7	223.4	338.7
1300	154.8	268.3	178.1	179.0	299.3	223.7	339.3
1310	155.4	269.0	178.8	179.6	299.9	224.0	339.9

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
1320	156.1	269.7	179.5	180.3	300.5	224.3	340.5
1330	156.8	270.4	180.2	180.9	301.1	224.6	341.1
1340	157.4	271.1	180.8	181.5	301.7	224.9	341.7
1350	158.1	271.8	181.5	182.1	302.3	225.2	342.3
1360	158.7	272.5	182.1	182.7	302.9	225.5	342.9
1370	159.3	273.2	182.8	183.3	303.5	225.8	343.5
1380	159.9	273.8	183.4	183.9	304.1	226.1	344.1
1390	160.6	274.5	184.0	184.5	304.6	226.4	344.6
1400	161.2	275.1	184.7	185.0	305.2	226.7	345.2

APPENDIX D

HATCH UNIT 1 P-T CURVES

VALID TO 48 EFPY

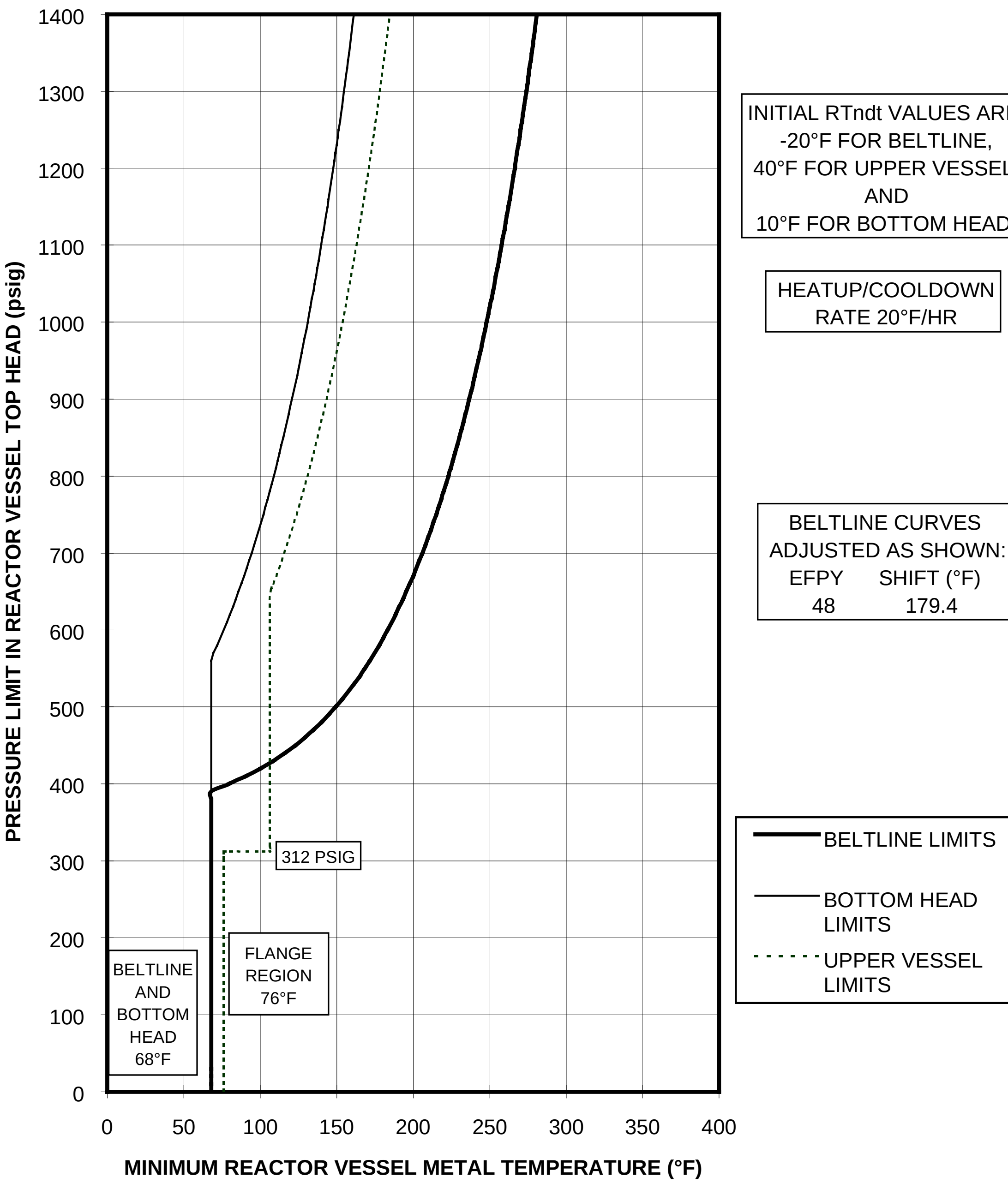

Figure D-1: P-T Curve for Unit 1 (Curve A)

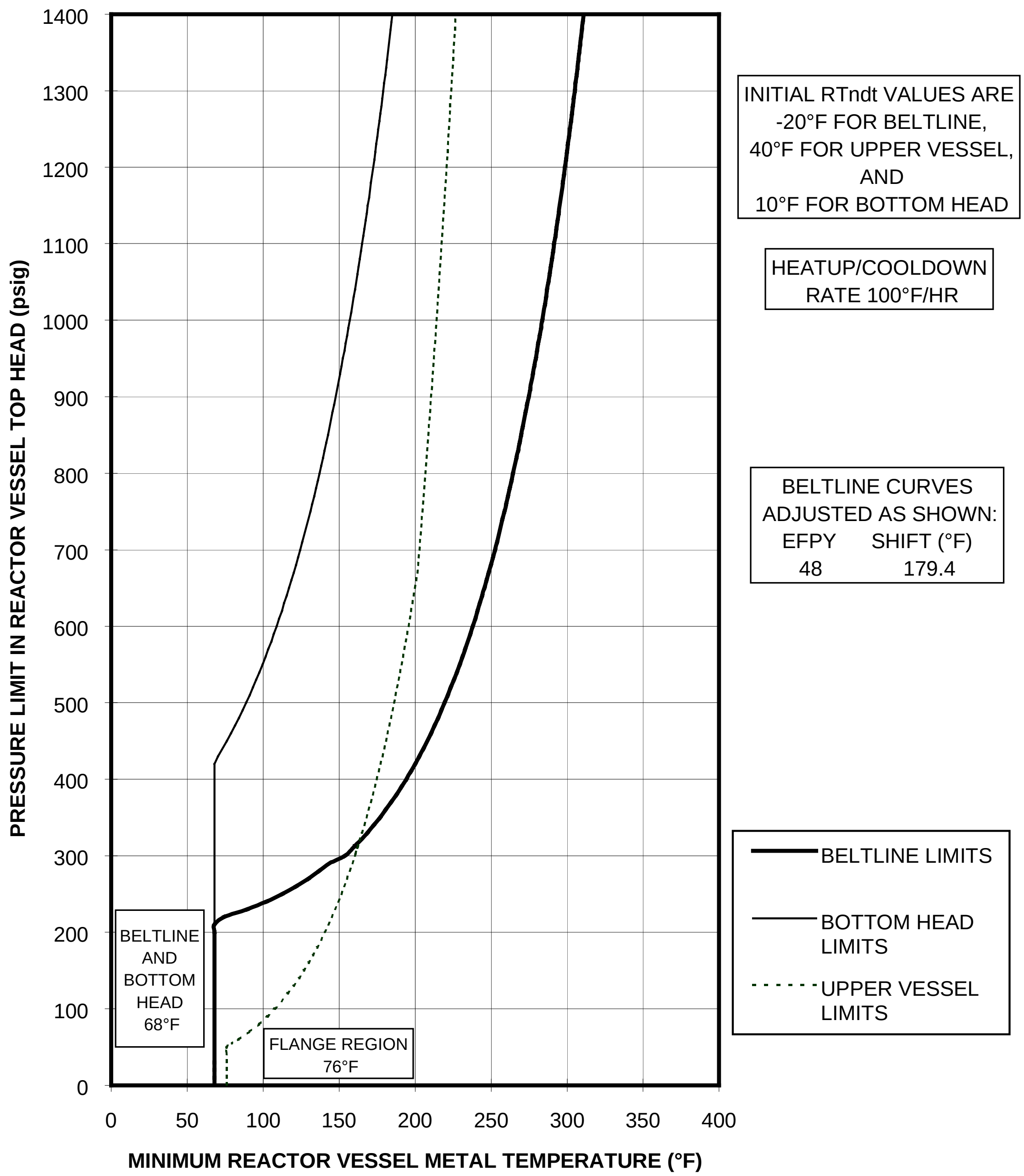

Figure D-2: P-T Curve for Unit 1 (Curve B)

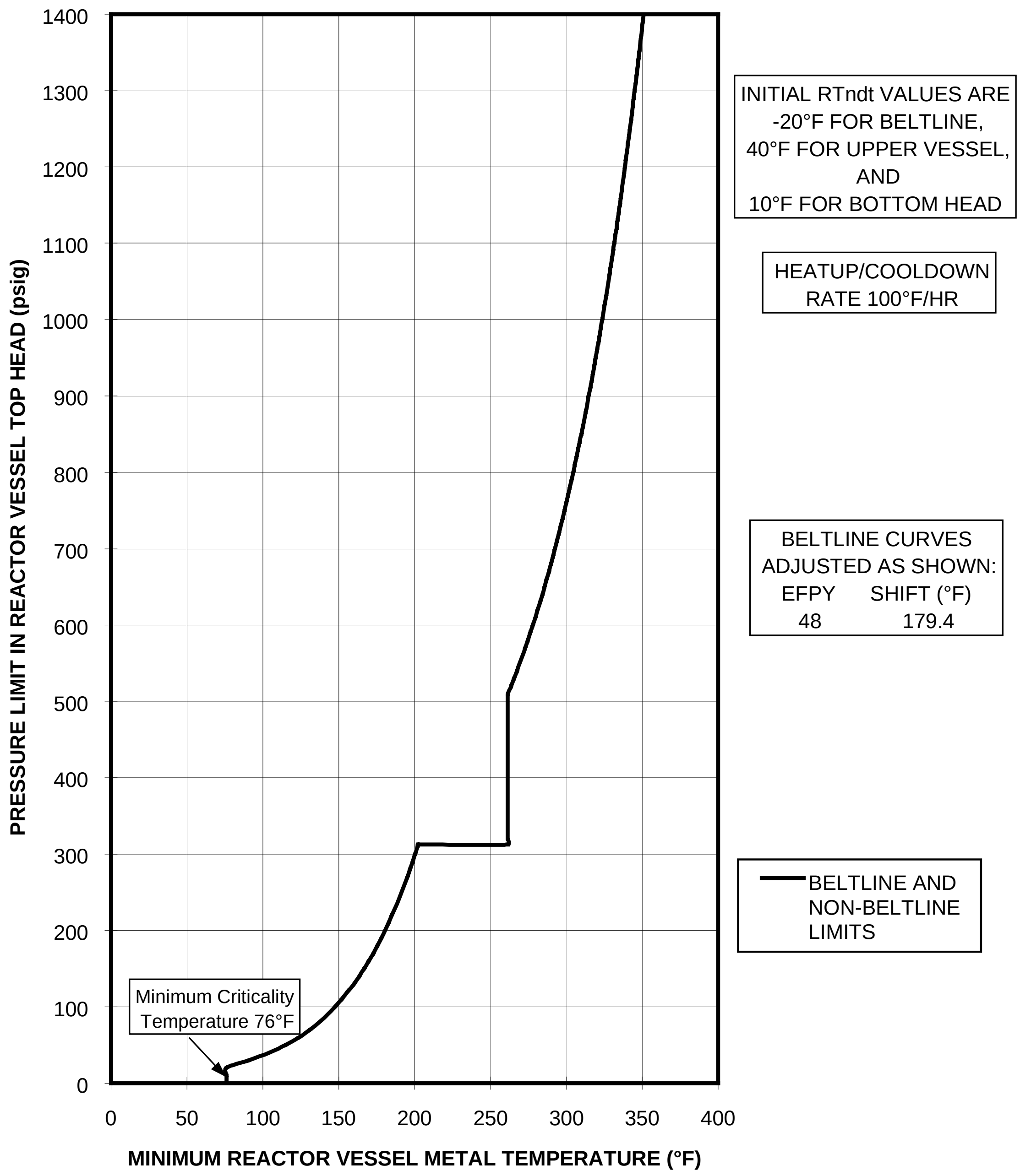

Figure D-3: P-T Curve for Unit 1 (Curve C)

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	74.4	145.2	185.2
230	68.0	68.0	76.0	68.0	89.6	147.4	187.4
240	68.0	68.0	76.0	68.0	102.0	149.4	189.4
250	68.0	68.0	76.0	68.0	112.5	151.4	191.4

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
260	68.0	68.0	76.0	68.0	121.6	153.3	193.3
270	68.0	68.0	76.0	68.0	129.7	155.1	195.1
280	68.0	68.0	76.0	68.0	136.9	157.0	197.0
290	68.0	68.0	76.0	68.0	143.4	158.7	198.7
300	68.0	68.0	76.0	68.0	153.7	160.3	200.3
310	68.0	68.0	76.0	68.0	159.0	162.0	202.0
312.5	68.0	68.0	76.0	68.0	160.3	162.3	202.3
312.5	68.0	68.0	106.0	68.0	160.3	162.3	261.4
320	68.0	68.0	106.0	68.0	163.9	163.5	261.4
330	68.0	68.0	106.0	68.0	168.5	165.1	261.4
340	68.0	68.0	106.0	68.0	172.8	166.6	261.4
350	68.0	68.0	106.0	68.0	176.9	168.0	261.4
360	68.0	68.0	106.0	68.0	180.7	169.4	261.4
370	68.0	68.0	106.0	68.0	184.3	170.8	261.4
380	68.0	68.0	106.0	68.0	187.7	172.1	261.4
390	68.0	68.0	106.0	68.0	191.0	173.4	261.4
400	68.0	79.5	106.0	68.0	194.2	174.7	261.4
410	68.0	90.6	106.0	68.0	197.1	176.0	261.4
420	68.0	100.2	106.0	68.0	200.0	177.2	261.4
430	68.0	108.7	106.0	70.3	202.8	178.4	261.4
440	68.0	116.2	106.0	73.2	205.4	179.6	261.4
450	68.0	122.9	106.0	76.1	208.0	180.7	261.4
460	68.0	129.1	106.0	78.8	210.4	181.8	261.4
470	68.0	134.7	106.0	81.5	212.8	182.9	261.4
480	68.0	140.0	106.0	84.0	215.1	184.0	261.4
490	68.0	144.8	106.0	86.5	217.3	185.1	261.4
500	68.0	149.3	106.0	88.8	219.5	186.1	261.4

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
510	68.0	153.6	106.0	91.1	221.5	187.1	261.5
520	68.0	157.6	106.0	93.3	223.6	188.1	263.6
530	68.0	161.4	106.0	95.5	225.5	189.1	265.5
540	68.0	165.0	106.0	97.6	227.5	190.1	267.5
550	68.0	168.4	106.0	99.6	229.3	191.1	269.3
560	68.0	171.7	106.0	101.5	231.1	192.0	271.1
570	69.5	174.8	106.0	103.5	232.9	192.9	272.9
580	71.8	177.7	106.0	105.3	234.6	193.8	274.6
590	74.0	180.6	106.0	107.1	236.3	194.7	276.3
600	76.1	183.3	106.0	108.9	237.9	195.6	277.9
610	78.2	186.0	106.0	110.6	239.5	196.5	279.5
620	80.2	188.5	106.0	112.3	241.1	197.3	281.1
630	82.1	190.9	106.0	113.9	242.6	198.2	282.6
640	84.0	193.3	106.0	115.5	244.1	199.0	284.1
650	85.9	195.6	106.7	117.1	245.6	199.8	285.6
660	87.7	197.8	108.6	118.6	247.0	200.6	287.0
670	89.4	199.9	110.4	120.1	248.4	201.4	288.4
680	91.1	202.0	112.2	121.6	249.8	201.9	289.8
690	92.8	204.0	114.0	123.0	251.2	202.3	291.2
700	94.4	206.0	115.7	124.4	252.5	202.8	292.5
710	96.0	207.9	117.4	125.8	253.8	203.2	293.8
720	97.6	209.8	119.0	127.1	255.1	203.6	295.1
730	99.1	211.6	120.6	128.4	256.3	204.0	296.3
740	100.6	213.3	122.2	129.7	257.6	204.4	297.6
750	102.0	215.0	123.7	131.0	258.8	204.8	298.8
760	103.5	216.7	125.2	132.3	259.9	205.2	299.9
770	104.8	218.3	126.7	133.5	261.1	205.6	301.1

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
780	106.2	219.9	128.1	134.7	262.3	206.0	302.3
790	107.6	221.5	129.5	135.9	263.4	206.4	303.4
800	108.9	223.0	130.9	137.0	264.5	206.7	304.5
810	110.2	224.5	132.2	138.2	265.6	207.1	305.6
820	111.4	226.0	133.5	139.3	266.7	207.5	306.7
830	112.7	227.4	134.8	140.4	267.7	207.9	307.7
840	113.9	228.8	136.1	141.5	268.8	208.3	308.8
850	115.1	230.2	137.3	142.6	269.8	208.7	309.8
860	116.3	231.5	138.6	143.6	270.8	209.0	310.8
870	117.5	232.9	139.8	144.7	271.8	209.4	311.8
880	118.6	234.1	140.9	145.7	272.8	209.8	312.8
890	119.7	235.4	142.1	146.7	273.8	210.1	313.8
900	120.8	236.7	143.3	147.7	274.7	210.5	314.7
910	121.9	237.9	144.4	148.7	275.7	210.9	315.7
920	123.0	239.1	145.5	149.7	276.6	211.2	316.6
930	124.0	240.3	146.6	150.6	277.5	211.6	317.5
940	125.1	241.5	147.7	151.6	278.4	212.0	318.4
950	126.1	242.6	148.7	152.5	279.3	212.3	319.3
960	127.1	243.7	149.8	153.4	280.2	212.7	320.2
970	128.1	244.8	150.8	154.3	281.1	213.0	321.1
980	129.1	245.9	151.8	155.2	281.9	213.4	321.9
990	130.0	247.0	152.8	156.1	282.8	213.7	322.8
1000	131.0	248.1	153.8	157.0	283.6	214.1	323.6
1010	131.9	249.1	154.7	157.8	284.5	214.4	324.5
1020	132.9	250.1	155.7	158.7	285.3	214.8	325.3
1030	133.8	251.1	156.6	159.5	286.1	215.1	326.1
1040	134.7	252.1	157.6	160.4	286.9	215.4	326.9

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
1050	135.6	253.1	158.5	161.2	287.7	215.8	327.7
1060	136.5	254.1	159.4	162.0	288.5	216.1	328.5
1070	137.3	255.0	160.3	162.8	289.3	216.5	329.3
1080	138.2	256.0	161.2	163.6	290.0	216.8	330.0
1090	139.0	256.9	162.0	164.4	290.8	217.1	330.8
1100	139.9	257.8	162.9	165.1	291.5	217.5	331.5
1110	140.7	258.7	163.7	165.9	292.3	217.8	332.3
1120	141.5	259.6	164.6	166.7	293.0	218.1	333.0
1130	142.3	260.5	165.4	167.4	293.7	218.4	333.7
1140	143.1	261.4	166.2	168.1	294.4	218.8	334.4
1150	143.9	262.2	167.0	168.9	295.2	219.1	335.2
1160	144.7	263.1	167.8	169.6	295.9	219.4	335.9
1170	145.5	263.9	168.6	170.3	296.6	219.7	336.6
1180	146.2	264.8	169.4	171.0	297.2	220.0	337.2
1190	147.0	265.6	170.2	171.7	297.9	220.4	337.9
1200	147.7	266.4	170.9	172.4	298.6	220.7	338.6
1210	148.5	267.2	171.7	173.1	299.3	221.0	339.3
1220	149.2	268.0	172.4	173.8	299.9	221.3	339.9
1230	149.9	268.8	173.2	174.5	300.6	221.6	340.6
1240	150.6	269.5	173.9	175.1	301.2	221.9	341.2
1250	151.3	270.3	174.6	175.8	301.9	222.2	341.9
1260	152.0	271.0	175.4	176.5	302.5	222.5	342.5
1270	152.7	271.8	176.1	177.1	303.2	222.8	343.2
1280	153.4	272.5	176.8	177.8	303.8	223.1	343.8
1290	154.1	273.3	177.5	178.4	304.4	223.4	344.4
1300	154.8	274.0	178.1	179.0	305.0	223.7	345.0
1310	155.4	274.7	178.8	179.6	305.6	224.0	345.6

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
1320	156.1	275.4	179.5	180.3	306.2	224.3	346.2
1330	156.8	276.1	180.2	180.9	306.8	224.6	346.8
1340	157.4	276.8	180.8	181.5	307.4	224.9	347.4
1350	158.1	277.5	181.5	182.1	308.0	225.2	348.0
1360	158.7	278.2	182.1	182.7	308.6	225.5	348.6
1370	159.3	278.9	182.8	183.3	309.2	225.8	349.2
1380	159.9	279.5	183.4	183.9	309.8	226.1	349.8
1390	160.6	280.2	184.0	184.5	310.3	226.4	350.3
1400	161.2	280.8	184.7	185.0	310.9	226.7	350.9