APPLICATION FOR LICENSE RENEWAL
SUMMARY OF CONTENTS

Volume 1

Volume 2

CHARLES H. CRUSE
Vice President
Nuclear Energy

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
4104954455

April 8, 1998

U.S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317& 50-318
Applicadtion for License Renewal

Baltimore Gas and Electric Company (BGE) hereby applies, pursuant to the provisions of Title 10 of the Code of Federal Regulations, Part 54 (10 CFR Part 54), for the renewal of the operating licenses for Calvert Cliffs Nuclear Power Plant (CCNPP) Units 1 and 2, issued pursuant to Section 104b of the Atomic Energy Act of 1954, as amended. Baltimore Gas and Electric Company requests that the licenses be extended 20 years beyond the current expiration dates. Pursuant to 10 CFR 54. 17(a) and 10 CFR 50.4(b)(3), the original and 13 copies are provided for an acceptance review. In addition, 26 copies of the environmental report (Volume 3 of the application) are included per 10 CFR 5 1.55(a).

This application for the renewal of the operating licenses for CCNPP Units 1 and 2 contains the information pursuant to the provisions of 10 CFR Part 54 for contents of an application. The following items, previously submitted as attachments to References (a) through (m), are included herein, technically unchanged

- The Integrated Plant Assessment (IPA) Methodology and the responses to the associated requests for additional information
- The The Limited Aging Analyses Evaluation; and
- The 35 system and commodity reports reflecting the IPA results.

All other parts of this application are submitted herein for the first time. The enclosed material is organized as follows:

Attachment (1) - General Information, Technical Information, and Technical Specifications.

1.0 General Information - Sections 1.0 through 1.10.
Appendix A - Technical Information - Sections 1.0 through 6.4.
Appendix B - UFSAR Supplement
Appendix C - Technical Specifications

Attachment (2) - Applicant’s Environmental Report - Operating License Renewal Stage

The content and format for system and commodity reports, and the environmental report, were based on the templates developed by BGE and NRC, through public meetings, as accepted or acknowledged by NRC in References (n) through (p).

As required by 10 CFR 54.21(b), current licensing basis changes, which have a material effect on the content of this application, will be identified at least annually while the application is under review. Baltimore Gas and Electric Company intends to provide the first update to this application on or before April 8, 1999.

Baltimore Gas and Electric Company is pleased to be involved in a new regulatory process that will be the stepping stone for the future of nuclear power in the United States, made possible by the rule-making carried through by the NRC. Baltimore Gas and Electric Company also appreciates the cooperation of the NRC Staff with BGE in determining appropriate level of detail, format, and content for this application.

We look forward to working with the NRC in our continued pursuit of license renewal. Should you have questions regarding this matter, we will be pleased to discuss them with you.

Very truly yours,

STATE OF MARYLAND :
: **TO WIT:**
COUNTY OF CALVERT :

I, Charles H. Cruse, being duly sworn, state that I am Vice President - Nuclear Energy, Baltimore Gas and Electric Company (BGE), and that I am duly authorized to execute and file this response on behalf of BGE. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other BGE employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

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Subscribed and sworn before me, a Notary Public in and for the State of Maryland and County of Calvert, this 8th day of April, 1998.

WITNESS my Hand and Notarial Seal: ______________________________
Donna L. McCready, Notary Public

My Commission Expires: ______________________________
Date

CHC/DLS/dlm

Attachment: (1) General Information, Technical Information, and Technical Specifications
(2) Applicant's Environmental Report - Operating License Renewal Stage

cc: R. S. Fleishman, Esquire
J. E. Silberg, Esquire
A. W. Dromerick, NRC
Director, Project Directorate I-1, NRC
H. J. Miller, NRC
R. I. McLean, DNR
Resident Inspector, NRC
J. H. Walter, PSC
C. I. Grimes, NRC
D. L. Solorio, NRC
C. M. Craig, NRC
D. R. Lewis, Esquire

REFERENCES:

(a) Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated January 1, 1996, “Revision 1 to Integrated Plant Assessment Methodology”

(b) Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated December 15, 1995, “Response to Request for Additional Information (RAI) Concerning the Baltimore Gas and Electric Company Report Entitled, Integrated Plant Assessment Methodology, dated August 18, 1995”

(c) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated May 23, 1997, “Request for Review and Approval of System and Commodity Reports for License Renewal”

(d) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 30, 1997, “Request for Review and Approval of System Reports for License Renewal”

(e) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 30, 1997, “Request for Review and Approval of Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System and Commodity Reports for License Renewal”

(f) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 30, 1997, “Request for Review and Approval of Commodity Report on Environmentally Qualified Equipment for License Renewal”

(g) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated August 21, 1997, “Request for Review and Approval of System and Commodity Reports for License Renewal”

(h) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated October 22, 1997, “Request for Review and Approval of System and Commodity Reports for License Renewal”

(i) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 14, 1997, “Request for Review and Approval of System and Commodity Reports for License Renewal”

(j) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated December 17, 1997, “Request for Review and Approval of System Reports for License Renewal”

(k) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated January 21, 1998, “Request for Review and Approval of System and Commodity Reports for License Renewal”

(l) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated March 3, 1998, “Request for Review and Approval of System and Commodity Reports for License Renewal”

(m) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated March 27, 1998, “Request for Review and Approval of Commodity and System Reports and the Time-Limited Aging Analyses Evaluation for License Renewal”

(n) Letter from Mr. S. C. Flanders (NRC), dated March 4, 1997, “Summary of Meeting with Baltimore Gas and Electric Company (BGE) on BGE License Renewal Activities”

(o) Memorandum from Ms. C. M. Craig (NRC) to Mr. D. B. Matthews (NRC), dated June 16, 1997, “Summary of Senior Management Meeting with Baltimore Gas and Electric Company (BGE) to Discuss License Renewal Environmental Report (ER) Template Process”

(p) Memorandum from Ms. C. M. Craig (NRC) to Mr. D. B. Matthews (NRC), dated August 21, 1997, “Summary of Severe Accident Mitigation Alternatives (SAMA) Methodology Meeting with Baltimore Gas and Electric Company (BGE)”

ATTACHMENT (1)

GENERAL INFORMATION, TECHNICAL INFORMATION,

AND TECHNICAL SPECIFICATIONS

ATTACHMENT (1)

GENERAL INFORMATION, TECHNICAL INFORMATION, AND TECHNICAL SPECIFICATIONS

CONTENTS

1.0 GENERAL INFORMATION

1.1 Name of Applicant

Baltimore Gas and Electric Company

1.2 Address of Applicant

Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, Maryland 21203-1475

1.3 Description of Business of Applicant

Baltimore Gas and Electric Company is an investor-owned utility engaged primarily in the business of producing and selling electricity and purchasing and selling natural gas. The Company, which was the first gas utility and one of the first electric utilities in the United States, serves an area that includes Baltimore City and all or part of 10 Central Maryland counties. The area served with electricity approximates 2,300 square miles with more than 1.1 million customers, while the area served with gas includes 600 square miles with more than 565,000 customers.

To service this area, the Company operates 10 electric generating plants in Central Maryland, including Calvert Cliffs Nuclear Power Plant (CCNPP). The Company also maintains shared ownership of three generating facilities in Pennsylvania. In addition, the Company is also a member of the Pennsylvania-New Jersey-Maryland Interconnection, a power pool interconnecting the transmission systems of eight energy companies. The Company's gas business purchases, transports, and sells natural gas through two gas plants and nine gate stations.

The Company's diversified business subsidiaries are organized into three groups, as follows:

- Constellation Holdings Companies - our power generation, financial investment, and real estate businesses;
- Constellation Energy Solutions™, Inc. and Subsidiaries - our energy marketing businesses; and
- BGE Home Product & Services, Inc. and Subsidiaries - our home products and commercial building systems businesses.

1.4 Legal Status and Organization

Baltimore Gas and Electric Company is a public utility incorporated under the laws of the State of Maryland with its principal office located in Baltimore, Maryland at the address stated above. Baltimore Gas and Electric Company is not owned, controlled, or dominated by an alien, a foreign corporation, or foreign government. Baltimore Gas and Electric Company makes this application on its own behalf and is not acting as an agent or representative of any other person.

ATTACHMENT (1)

1.0 GENERAL INFORMATION

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

Directors:

Mr. Christian H. Poindexter
Chairman of the Board, President & Chief Executive Officer
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Mr. H. Furlong Baldwin
Chairman of the Board & Chief Executive Officer
Mercantile Bankshares Corporation
P.O. Box 1477
Baltimore, MD 21203

Mrs. Beverly B. Byron
4000 Cathedral Ave., N.W. - #848-B
Washington, DC 20016

Mr. J. Owen Cole
Director, First Maryland Bancorp
Chairman, First National Bank of Md. Trust Committee
P.O. Box 1596
Baltimore, MD 21203

Mr. Dan A. Colussy
1318 Kinloch Circle
Arnold, MD 21012

Mr. Edward A. Crooke
Vice Chairman - BGE
Chairman of the Board, President & Chief Executive Officer -
Constellation Enterprises™, Inc.
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203

Mr. James R. Curtiss, Esq.
Partner - Winston & Strawn
1400 L Street, N.W.
Washington, DC 20005-3502

Mr. Jerome W. Geckle
Chairman of the Board (Ret.)
PHH Corporation
P.O. Box 305
Maryland Line, MD 21105

Dr. Freeman A. Hrabowski, III
President
University of Maryland Baltimore County
1000 Hilltop Circle
Baltimore, MD 21250

Ms. Nancy Lampton
Chairman and Chief Executive Officer
American Life and Accident Insurance
Company of Kentucky
3 Riverfront Plaza
Louisville, Kentucky 40202

Mr. George V. McGowan
Chairman of the Executive Committee of
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203

George L. Russell, Jr., Esq.
Partner
Piper & Marbury
1100 Charles Center South
36 South Charles Street
Baltimore, MD 21201

Mr. Michael D. Sullivan
Chairman
Golf America Stores
10001 Franklin Square Drive
Baltimore, MD 21236

Principal Officers:

Mr. Christian H. Poindexter
Chairman of the Board, President & Chief Executive Officer
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Edward A. Crooke
Vice Chairman - BGE
Chairman of the Board, President & Chief Executive Officer -
Constellation Enterprises™, Inc.
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

ATTACHMENT (1)

1.0 GENERAL INFORMATION

Robert E. Denton
Executive Vice President-Generation
Baltimore Gas & Electric Company
1650 Calvert Cliffs Parkway
Lusby, MD 20657

Frank O. Heintz
Executive Vice President-Utility Operations
Vice President - Gas
Baltimore Gas & Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Thomas F. Brady
Vice President, Customer Service & Distribution
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Charles H. Cruse
Vice President - Nuclear Energy
Baltimore Gas and Electric Company
1650 Calvert Cliffs Parkway
Lusby, MD 20657-4702

Carserlo Doyle
Vice President - Electric Interconnection and Transmission
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Linda D. Miller
Vice President - Management Services
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Ronald W. Lowman
Vice President - Fossil Energy
Baltimore Gas and Electric Company
Fort Smallwood Road Complex
1000 Brandon Shores Road
Baltimore, MD 21226

Gregory C. Martin
Vice President - General Services
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

David A. Brune
Vice President & Chief Financial Officer - Finance and Accounting
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Stephen F. Wood
Vice President - BGE
President & Chief Executive Officer - Constellation Energy
Projects & Services
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Sharon S. Hostetter
Vice President - Marketing and Sales
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Richard M. Bange, Jr.
Controller - Accounting
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Thomas E. Ruszin, Jr.
Treasurer - Accounting
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

1.5 Class and Period of License Applied For

The Company requests renewal of the Class 104b operating licenses for CCNPP Units 1 and 2 (license numbers DPR-53 and DPR-69) for a period of 20 years beyond the expiration of the current licenses, currently midnight, July 31, 2014, and midnight, August 13, 2016, respectively. This request includes application for renewal of those source, special nuclear material, and by-product licenses that are combined in the operating licenses.

The nuclear station, known as CCNPP Units 1 and 2, is located on the west shore of the Chesapeake Bay in Calvert County, Maryland, some 45 miles southeast of Washington, DC, and

60 miles south of Baltimore. Operation of the twin Combustion Engineering pressurized-water reactors results in an approximate net electrical output of 845 megawatts for each reactor. Details concerning the plant and the site are contained in the Updated Final Safety Analysis Report for Calvert Cliffs Nuclear Power Plant Units 1 and 2.

1.6 Construction Dates

The Company does not propose to construct or alter a production or utilization facility solely for the purpose of this application.

1.7 Regulatory Agencies

The Public Service Commission of Maryland has jurisdiction over the rates and services provided by the Company's utility operations. Their address is:

Public Service Commission of Maryland
6 St. Paul Centre
Baltimore, MD 21202-6806

1.8 Local News Publications

Local news publications that circulate in the area around CCNPP and that are considered appropriate to give reasonable notice of the application are:

Calvert Independent Newspaper	P.O. Box 910 Prince Frederick, MD 20678
Calvert County Recorder	P.O. Box 485 Prince Frederick, MD 20678
Enterprise Newspaper	P.O. Box 700 Lexington Park, MD 20653

1.9 Indemnity Agreement

The current indemnity agreement (B-70) for licenses DPR-53 and DPR-69 does not contain a specific expiration term. Expiration is expressed in terms of the time of the expiration of the licenses specified. Therefore, conforming changes to account for the expiration term of the proposed renewed licenses are unnecessary.

1.10 Communications

All communications to the applicant pertaining to this application should be sent to:

Mr. Charles H. Cruse
Vice President - Nuclear Energy
Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
1650 Calvert Cliffs Parkway
Lusby, MD 20657-4702

In addition, it is requested that copies be sent to the Company's General Counsel and Washington counsel:

Mr. Robert S. Fleishman, Esquire
General Counsel
Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, MD 21203-1475

Mr. David R. Lewis, Esquire
Shaw, Pittman, Potts and Trowbridge
2300 N Street, NW
Washington, DC 20037

ATTACHMENT (1)

APPENDIX A - TECHNICAL INFORMATION

1.0 INTRODUCTION

This appendix contains the Integrated Plant Assessment (IPA) Methodology, the Time Limited Aging Analyses evaluation, and the IPA results. The IPA results were produced and formatted in accordance with the Methodology and the template developed by Baltimore Gas and Electric Company and NRC staff.

The contents of Appendix A, beyond this introduction, are as follows:

6.1 Cables
6.2 Electrical Commodities
6.3 Environmentally Qualified Equipment
6.4 Instrument Lines

1.0 INTRODUCTION

The purpose of this Methodology is to document the plant-specific process used for conducting the Integrated Plant Assessment (IPA) for Aging and the Time-Limited Aging Analysis (TLAA) Review for the Calvert Cliffs Nuclear Power Plant (CCNPP) in order to produce the information specified in the License Renewal (LR) Rule Section 54.21 (Contents of Application - Technical Information).

During the performance of the IPA process steps described in this methodology, all plant structures and components (SCs) which are subject to aging management review (AMR) are identified. For the identified SCs, justification is developed that demonstrates that the effects of aging on the intended functions of these SCs are adequately managed (see definitions).

In addition to the IPA process, this methodology describes the TLAA review process which complements the IPA. This review identifies TLAAs in the CCNPP Current Licensing Basis (CLB) which meet the specific criteria defined in the LR Rule. It also identifies exemptions still in effect which are based on a TLAA. For each of the identified analyses, the review task provides justification that the analysis is valid for the period of extended operations, provides a means for updating the analysis so that it will be valid for the period of extended operation or documents that the aging issue covered by the TLAA is adequately managed.

The IPA process for CCNPP has been divided into several distinct tasks. Each of these tasks, as well as the TLAA review task, will be discussed in subsequent sections of this methodology. The purpose of this section of the methodology is to provide general background information regarding the Baltimore Gas & Electric Company (BGE) Life Cycle Management (LCM) Program and to briefly introduce the topics presented in the following sections of IPA Methodology.

1.1 Background

Baltimore Gas and Electric Company has embarked on a comprehensive, long-term LCM Program for CCNPP, Units 1 and 2. The LCM Program directly supports BGE's Corporate Operational Strategy of preserving the long-term operation of CCNPP. In this capacity, the LCM Program governs the major evaluations to determine the reconfiguration of systems and structures (SSs) to improve reliability, increase availability, reduce operations and maintenance cost, provide recommendations to the capital improvement plan for the site, prepare License Renewal Applications (LRAs) for both Units, as well as contingency plans for decommissioning. The LCM Program also coordinates site activities regarding reactor vessel issues (including pressurized thermal shock [PTS]) and provides input to corporate Generation Planning and Accounting offices for strategic generation planning. Additional services governed by the LCM Program include project management of the 24-month cycle project, the Instrumentation and Controls Upgrade Project and Power Uprate Feasibility Studies.

Because of its role in preserving the long-term operation of CCNPP, the LCM Program has integrated specific design, engineering, operations, and maintenance activities to focus attention on material conditions and aging management. The LCM Program involves all five Nuclear Energy Division departments and a number of other BGE divisions.

1.2 Methodology Summary

The BGE IPA methodology is based on the premise that, with the possible exception of the detrimental effects of aging on the functionality of certain systems, structures and components (SSCs) in the period of extended operation, the plant's CLB ensures an adequate level of safety for continued plant operations. Figure 1-1 illustrates the flow path of the BGE IPA, as implemented at CCNPP. The relationship between the IPA and the TLAA review is shown in Figure 1-2.

The Methodology is divided into eight sections. The contents of Sections 2.0 through 8.0 are summarized below.

Section 2.0, IPA Methodology Bases and Definitions, contains the following information:

- Definitions of important terms and acronyms that are integral to the IPA methodology.
- Assumptions and initial conditions on which the IPA methodology is based.
- Source documents which were used to develop the methodology.

Section 3.0, System Level Scoping, describes the scoping steps where SSs that perform specific functions (described in Section 54.4 of the LR Rule) are identified as the initial scope of equipment, which will be the subject of the IPA for aging.

Section 4.0, Component Level Scoping, describes how the SS intended functions are identified in more detail, and how individual components of the SS are evaluated to determine which components contribute to the intended functions. This section provides two parallel processes for component level scoping, one used for system components and the other for structural components.

Section 5.0, Pre-Evaluation, describes the various steps which are undertaken to determine which components are "subject to AMR" in the subsequent task of the IPA.

Section 6.0, AMR, describes how the determination is made that existing, modified or new programs or activities for those SCs subject to AMR adequately manage the effects of aging.

Section 7, Commodity Evaluations, describes alternate IPA process steps used at CCNPP for specific commodity groups.

Section 8.0, TLAA Review, describes the process for selecting TLAAs which need to be addressed for LR and methods for addressing the identified analyses.

IPA Flow Diagram

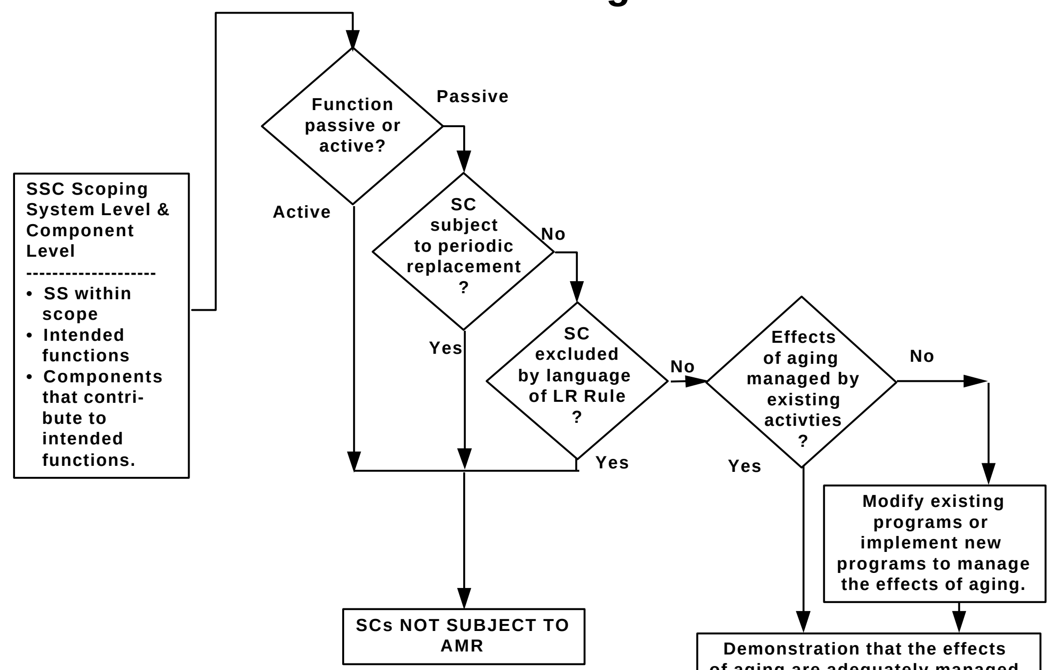

Figure 1-1

IPA Process and TLAA

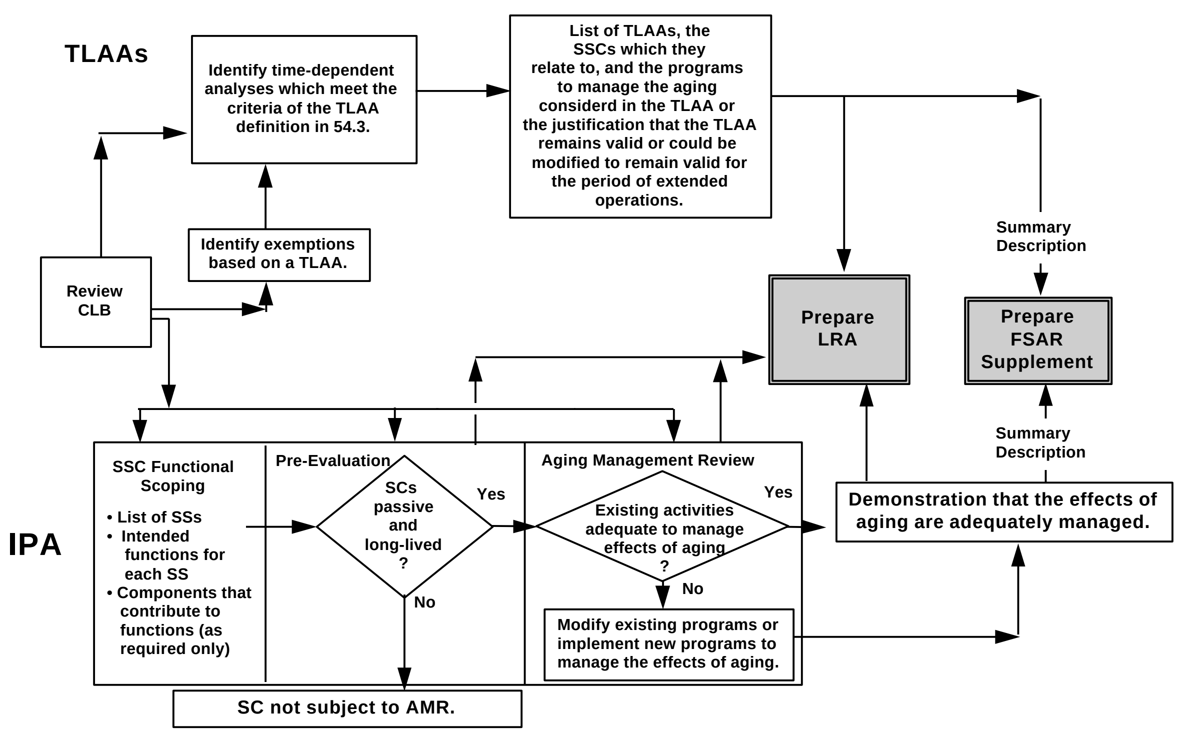

Figure 1-2

2.0 IPA METHODOLOGY BASES AND OVERVIEW

This section defines the terms and acronyms (Section 2.1) that are used throughout the methodology. Section 2.2 presents the assumptions and initial conditions on which the IPA methodology is based. Finally, Section 2.3 presents an overview of the methodology tasks.

2.1 Definitions

There are a number of terms and acronyms that are used throughout this methodology. These terms are defined below and the meaning of acronyms is provided in Table 2-1. Many of the following definitions, identified by *, are taken from the LR Rule, Sections 54.3, 54.4, 54.21, and 54.31 or from the Statements of Consideration (SOC) to the Rule. The specific rule section which is the source of the definition is noted parenthetically for definitions marked with an asterisk.

1. **Adequately Managed -** The effects of aging are adequately managed for a group of SCs if their intended passive functions will be maintained consistent with the CLB during the period of extended operations.

2. **Age-Related Degradation** - A change in SSC performance or physical or chemical properties resulting in whole or part from one or more aging mechanisms. Examples of this type of change include changes in dimension, ductility, fatigue resistance, fracture toughness, mechanical strength, polymerization, viscosity, and dielectric strength.

3. **Aging Mechanisms** - The physical or chemical processes that result in degradation. These mechanisms include, but are not limited to, fatigue, erosion, corrosion, erosion/corrosion, wear, thermal embrittlement, radiation embrittlement, microbiologically-induced effects, creep, and shrinkage.

4. **Critical Safety Function (CSF) -** A condition or action that prevents core damage or minimizes radiation release to the public. A CSF may be fulfilled through automatic or manual actuation of a system or systems, from passive[1] system performance, from inherent plant design, or from operator action while following recovery guidelines set down in procedures. The seven CSFs include:

   Reactivity Control
   Reactor Coolant System (RCS) Pressure and Inventory Control
   RCS Heat Removal
   Containment Isolation
   Containment Environment Control
   Radiation Control
   Vital Auxiliaries (VA)

[1] The definition of CSF is taken directly from CCNPP Q-List documentation which pre-dates the current version of the LR rule. Therefore, the term "passive" in the CSF definition is not necessarily identical to the term defined in this methodology and used for convenience in the SOC accompanying 10 CFR Part 54.

5.(*) **Current Licensing Basis (CLB)** - The set of NRC requirements applicable to a specific plant and a licensee's written commitments for assuring compliance with and operation within applicable NRC requirements, and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100, and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design basis information defined in 10 CFR 50.2, as documented in the most recent Final Safety Analysis Report (FSAR) as required by 10 CFR 50.71, and the licensee's commitments remaining in effect that were made in docketed licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports. [§54.3]

6. **Device Type (DT)** - A more specific categorization of components according to their function and design. Equipment types (ETs) are broken into a number of DTs. For example, the ET for valves include DTs hand valve, check valve, control valve, and others. Device types are the starting point for the grouping process in the AMR task. Components are grouped by DT as they enter this task. Device types may be divided to form more specific groups if needed, or the DT may define the component group for evaluation. Whenever the LR Rule calls for justifications for SCs, the discussions provided by the BGE IPA process are at the device-type level.

7. **Equipment Type (ET)** - A general categorization of components according to their function and design. Examples of specific ETs are valve, piping, instrument, etc. For those SCs subject to AMR, the list of age-related degradation mechanisms (ARDMs) which needs to be addressed is developed for each ET. Structural components are categorized into generic groupings of concrete/architectural and steel components.

8. **Extended Operations, Period of** - The additional amount of time beyond the expiration of the current operating license that is requested in the renewal application.

9. **Function Catalog** - A Function Catalog for a particular intended function of a system consists of the list of all system components required to support that intended function that are within the boundary of the given system.

10. **Functional Requirements -** The general, high level functions which an SS may be called on to perform. The functional requirements are used during the system scoping process to establish conceptual boundaries so that when a detailed function is determined to be an intended function, the evaluator will know which SS to associate the function with. The term "functional requirements" is used to distinguish these high level functions from the detailed intended functions contained in the screening tools and used during the component level scoping process.

11.(*) **Integrated Plant Assessment (IPA)** - A licensee assessment that demonstrates that a nuclear power plant facility's systems, structures, and components requiring AMR in accordance with §54.21(a) for LR have been identified and that the effects of aging on the functionality of such SCs will be managed to maintain the CLB, such that there is an acceptable level of safety during the period of extended operations. [§54.3]

12.(*) **Intended Function -** Those functions that are the bases for including SSCs within the scope of LR. [§54.4b]

13. **Licensed Life** - The maximum period of operations, in calendar years, as defined by statute. For CCNPP, this period is 40 years.

14. **Life Cycle Management Evaluation Database (LCMEVAL)** - A computer-based application which is used to facilitate the component level scoping process for systems. The LCMEVAL was created, tested and documented, in accordance with the BGE Quality Assurance Program for Software Development, to justify its use in the safety-related (SR) scoping tasks. Master Equipment List data, Q-List data, drawing references, and other information useful in the scoping process are extracted one system at a time from controlled plant databases, loaded into LCMEVAL, and made available to the evaluator. The LCMEVAL helps to streamline the scoping process by automating key steps and facilitating storage and printing of the results.

15.(*) **Long-Lived** - Components are considered to be long-lived if they are not subject to periodic replacement based on qualified life or specified time period. [§54.21(a)(1)]

16. **Maintenance Strategy** - A philosophy regarding the level and type of maintenance that a component will receive throughout its life cycle. An adequate maintenance strategy is defined by the following program attributes:

a. **Discovery** - Identification of performance or condition degradation;

b. **Assessment/analysis** - Comparison with criteria or other guidance to determine the degree of the degradation;

c. **Corrective action** - Mitigation of the degradation; and

d. **Confirmation/Documentation** - Verification and documentation that the intended function was restored from its degraded condition as a result of the corrective action.

17. **Master Equipment List (MEL)** - A compilation of the NUCLEIS Equipment Technical Database (NETD) technical data on equipment for a given system.

18.(*) **Nuclear Power Plant** - A commercial nuclear power facility of a type described in 10 CFR 50.21(b) or 50.22. [§54.3]

19. **NUCLEIS Database** - A mainframe computer-based information system used to initiate, plan, schedule, track and provide a history of maintenance for all plant components. NETD is an acronym used to denote the NUCLEIS Equipment Technical Database, which is that part of the NUCLEIS information system, indexed by component, which contains information specific to each component.

20.(*) **Passive -** A function is said to be passive if it is performed without moving parts or a change in configuration or properties in order to perform the function during normal operating conditions or in response to an accident. [§54.21(a)(1)].

21. **Plant Event Evaluations -** Pre-existing evaluations which show compliance with regulations concerning fire protection (FP), environmental qualification (EQ), PTS, anticipated transients without scram (ATWS) and station blackout (SBO). These evaluations provide the bases for in-scope determinations under §54.4 Criterion 3.

22. **Plausible Age-Related Degradation Mechanisms (ARDMs)** - (See Aging Mechanisms) An ARDM is considered plausible for a specific component if, when allowed to continue without any prevention or mitigation measures or enhanced monitoring techniques, it could not be shown that the component would maintain its capability to perform its intended, passive function throughout the period of extended operation.

23. **Program/Activity (PA)** - A group of procedures, formal or informal, that provide reasonable assurance that SSCs are capable of fulfilling their intended functions. This may range from a formalized, long-established group of procedures to a one-time only procedure.

24.(*) **Renewal Term** - The period of time that is the sum of the additional amount of time beyond the expiration of the operating license (not to exceed 20 years) that is requested in the renewal application plus the remaining number of years on the operating license currently in effect. [§54.31(b)]

25. **Screening Tool** - A summary of source document(s) compiled through the research of an event/topic which contains lists of responding SSCs and their intended functions.

26. **Structure** - The term structure, when used as a stand-alone term in this methodology, refers to a building. When a component of a structure is referred to, the term “structural component” is used for clarity.

27.(*) **Structures and Components (SCs)** - The phrase “structures and components” applies to matters involving the IPA required by §54.21(a) because the AMR required within the IPA should be a component level review rather than a more general system level review. [SOC i.e., 80 FR 22462] In this Methodology, the term “structural components and components” (SCs) refers to the component level concept.

28.(*) **Systems, Structures and Components (SSCs) -** Throughout these discussions, the term “systems, structures and components” is used when referring to matters involving the discussions of the overall renewal review, the specific LR scope[2], TLAA and the LR finding. [SOC i.e., 80 FR 22462]

2 Note that the CCNPP scoping process is a two-step process with the initial step being conducted at the SSC or system level. The second step is conducted at the component level and the term SCs applies in this step.

29.(*) **Structure or Component Subject to Aging Management Review (AMR)** - Structures and components subject to an AMR shall encompass those SCs:

(1) That perform an intended function, as described in §54.4, without moving parts or a change in configuration or properties; and

(2) That are not subject to replacement based on a qualified life or specified time period. [§54.21(a)(1)]

30.(*) **Systems, Structures, and Components within the Scope of LR** - are:

(1) Safety-related SSCs, which are those relied on to remain functional during and following design basis events (DBEs) [as described in 10 CFR 50.49(b)(1)] to ensure the following functions:

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

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

(iii) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines.

(2) All non-safety-related (NSR) SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (1) (i), (ii), or (iii) of this definition.

(3) All SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for FP (10 CFR 50.48), EQ (10 CFR 50.49), PTS (10 CFR 50.61), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63). [§54.4a]

31.(*) **Time-Limited Aging Analysis (TLAA)** - those licensee calculations and analyses that:

(1) Involve SSCs within the scope of LR as delineated in §54.4(a);

(2) Consider the effects of aging;

(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;

(4) Were determined to be relevant by the licensee in making a safety determination;

(5) Involve conclusions or provide the basis for conclusions related to the ability of the SSCs to perform its intended functions, as delineated in §54.4(b); and

(6) Are contained or incorporated by reference in the CLB.

[§54.3]

Table 2-1 List of Acronyms

AFW	Auxiliary Feedwater
AMR	Aging Management Review
ARDM	Age-Related Degradation Mechanism
ATWS	Anticipated Transient Without Scram
BGE	Baltimore Gas and Electric Company
CCNPP	Calvert Cliffs Nuclear Power Plant
CCW	Component Cooling Water
CEA	Control Element Assembly
CLB	Current Licensing Basis
CSF	Critical Safety Function
DBE	Design Basis Event
DT	Device Type
EP	Electrical Panel
EQ	Environmental Qualification
ET	Equipment Type
FP	Fire Protection
FSAR	Final Safety Analysis Report
IL	Instrument Line
IPA	Integrated Plant Assessment
IR	Issue Report
LCM	Life Cycle Management
LCMEVAL	Life Cycle Management Evaluation Database
LR	License Renewal
LRA	License Renewal Application
MEL	Master Equipment List
NETD	NUCLEIS Equipment Technical Database
NSR	Non-Safety-Related
PAM	Post-Accident Monitoring
PB	Pressure Boundary
PTS	Pressurized Thermal Shock
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
SBO	Station Blackout
SCs	Structures and Components
SG	Steam Generator
SOC	Statements of Consideration
SR	Safety-Related
SS	System and Structure
SSCs	Systems, Structures and Components
TLAA	Time-Limited Aging Analysis
UFSAR	Updated Final Safety Analysis Report
VA	Vital Auxiliary

2.2 Assumptions and Initial Conditions

The IPA methodology relies on a number of basic assumptions and initial conditions. They include:

2.2.1 The scoping methodology assumes that the most effective approach in scoping SSCs is the use of two levels of scoping, i.e., system level and component level. This segregates SSCs into logical, manageable pieces and is similar to approaches used during design, construction, and operation.

2.2.2 The criteria underlying the system level and component level scoping processes are identical.

2.2.3 The purpose of the IPA methodology is to provide a basis for the procedures which implement the steps of the scoping task and the steps of the IPA. Sections 1 through 5 of the methodology implement the requirements of §54.21(a)(2) to describe and justify the methods used in §54.21(a)(1).

Sections 6, 7 and 8 go beyond the requirements of §54.21(a)(2) by describing the methods used to perform the AMR and TLAA review. However, the description of these methods should facilitate a better understanding of the results produced by these tasks. The results will be documented in the LRA and FSAR Supplement.

2.2.4 The IPA methodology is designed to make maximum use of existing BGE programs, system and equipment lists, documents, and databases to reduce duplication of effort and produce implementation results which reference equipment nomenclature already familiar to site personnel.

2.2.5 During the scoping task, tanks which are included in more than one site documentation system, e.g., both on the site structures list and as a component of a particular system in an MEL, are included only as components of a system during the IPA process.

2.2.6 Because the tasks described in this methodology are essential for providing the justification for the safety finding of §54.29, these tasks are performed in accordance with the BGE quality assurance program.

2.2.7 Structural components and components, which contribute to one or more passive functions and are long-lived, require evaluation to demonstrate that the effects of aging are adequately managed.

There are a variety of methods available for managing the effects of aging in order to assure the passive intended function. The appropriate method for a given situation depends on a number of factors, including the severity of the aging effects and the level of concern associated with degraded equipment condition. This correlation of the effects of aging to the appropriate level of aging management is discussed in detail in Section 6 of this methodology.

2.3 IPA Methodology Overview

The IPA methodology describes two scoping tasks, two IPA tasks, and the TLAA review task. Each is described briefly below.

2.3.1 System Level Scoping

System level Scoping (Section 3) establishes boundaries for plant SSs, develops screening tools which capture the §54.4 scoping criteria, and then applies the tools to identify SSs within the scope of LR.

2.3.2 Component Level Scoping

Component Level Scoping (Section 4) evaluates the components of SSs within the scope of LR to identify those which are required for the SS to perform its intended functions. Such components are designated as within the scope of LR.

2.3.3 Pre-Evaluation

Pre-evaluation (Section 5) determines which SCs, of those within the scope of LR, are subject to AMR. During the performance of this task, the following categories of SCs are eliminated from further IPA review:

- Those which contribute only to active functions;
- Those which are replaced based on time or qualified life; and
- Those specifically excluded by the Rule language in §54.21(a)(1)(i).

The result of this task is the list of all SCs in the given system which will be subject to AMR.

2.3.4 AMR

The AMR task (Section 6) demonstrates that the effects of aging are adequately managed (see Definitions). Several different techniques for developing this justification are presented in this section. All the techniques provide the demonstration necessary to support the finding of §54.29 with respect to the management of effects of aging.

2.3.5 Commodity Evaluations

Six commodity evaluations are described in Section 7 of the IPA Methodology. These techniques are used for a specific set of components found in a number of systems, but which perform the same or similar functions regardless of their system.

2.3.6 TLAA Review

The TLAA Review is described in Section 8 of the IPA methodology. This task searches the CCNPP CLB, independent of the IPA process, to locate issues related to the current operating life of the plant which also meet certain other specified criteria. For the identified TLAA, the justification is provided that the time-limited issue is or will be addressed through one of the three approaches specified in §54.21(c). Note that this task is not technically part of the IPA, but its description is included in the IPA Methodology for convenience.

TABLE 2-2

SOURCE DOCUMENTS

This list of documents represents the sources used for developing the IPA methodology. This table does not represent all references which might be used in actually performing the tasks described in the methodology. References used in the application of the methodology to a specific system are included in the implementing procedures and in the task-specific results.

1. Life Cycle Management/License Renewal Program Management Plan, Revision 2, April 1992
2. 10 CFR Part 54, “Nuclear Power Plant License Renewal, Final Rule,” May 8, 1995
3. 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities” (routinely updated)
4. 10 CFR Part 100, Appendix A, "Seismic and Geologic Siting Criteria for Nuclear Power Plants," January 1, 1991
5. Calvert Cliffs Nuclear Power Plant, Units 1 and 2, Updated Final Safety Analysis Report, Revision 17, November 1994
6. Calvert Cliffs Nuclear Power Plant, Units 1 and 2, Technical Specifications Manual, through Amendment 205 (May 1995) for Unit 1, and Amendment 183 (April 1995) for Unit 2
7. CCNPP Design Standard, “Structure and Component Evaluation,” (DS-011) Revision 0, June 7, 1995
8. CCNPP Design Standard “Control of Equipment Technical Databases,” (DS-032) Revision 0, January 25, 1995
9. CCNPP System Descriptions (various revisions)
10. NRC Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3
11. CCNPP Plant Drawings (various)
12. NUREG-1377, "Listing of Nuclear Plant Aging Research Reports," and the reports themselves
13. Industry Technical Reports on PWR Reactor Vessel, PWR Reactor Vessel Internals, PWR Containment, PWR Reactor Coolant System, Class 1 Structures and Environmentally-Qualified Cables in Containment

3.0 SYSTEM LEVEL SCOPING

This section describes how all plant SSs are reviewed to determine those that are within the scope of LR. This is accomplished through application of the system scoping process (Figure 3-1).

Determining which SSCs are within the scope of LR is the first major task described in the IPA methodology. Section 54.21(a)(1) of the LR Rule states that the IPA must be conducted -

> *For those systems structures and components within the scope of this part, as delineated in §54.4, . . .*

In other words, the results of the system level and component level scoping tasks are the starting point of the IPA.

System level scoping consists of several activities. Section 3.1 describes how SSs are identified and listed. Section 3.2 describes the development of conceptual boundaries for SSs. Section 3.3 describes the development of system screening tools. Section 3.4 describes how all in-scope SSs are identified. Section 3.5 describes how the scoping results are documented.

3.1 Identification of SSs

The SS listing for CCNPP is provided in Table 3-1. The CCNPP Design Standard for "Control of the Equipment Technical Databases," (See Table 2-1, Reference 8) was used to develop the list of systems at CCNPP. This approach ensures that system designations are consistent with those established for current site programs and the MEL. The structures list was obtained through a review of the latest revision to the Plant Property and Building Drawing No. 61-502-E. Tanks identified on this drawing are not included in the list of structures since tanks are included as components of associated systems.

3.2 Define Conceptual Boundaries

This step of the system level scoping process tabulates some basic information about each of the SSs listed in Table 3-1. This information, referred to as the “conceptual boundaries” of the SS, is needed to ensure a consistent understanding of what is meant by each of the SS names in this table.

The identification of the SS conceptual boundaries is accomplished by reviewing the CCNPP Updated Final Safety Analysis Report (UFSAR), Technical Specifications, and System Descriptions, as well as conducting interviews with experienced plant personnel. For each of the SSs listed in Table 3-1, a brief system description is developed and the functional requirements are identified. The description includes a listing of the major components and major system interfaces for each SS. The functional requirements list includes only the general, high level functions that an SS may be called on to perform. In the follow-on steps of the scoping process, whenever an intended function is identified, the conceptual boundaries allow the evaluator to determine which SS the intended function should be associated with. The list of functional requirements does not represent a detailed list of intended functions, but it is sufficient to establish the conceptual boundaries of SSs. The component level scoping task (described in Section 4) develops a detailed list of SS intended functions.

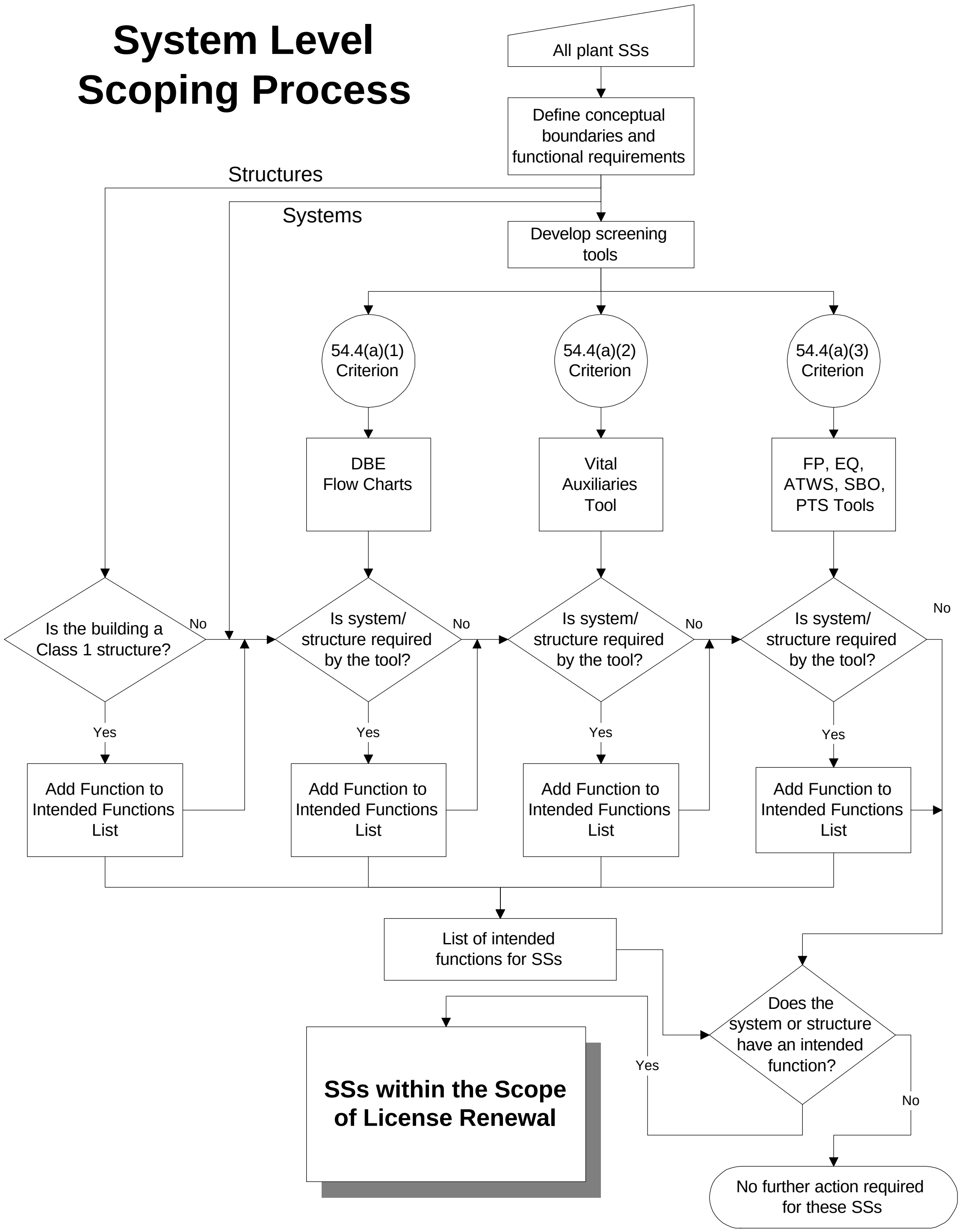
System Level
Scoping Process
All plant SSs
Define conceptual boundaries and functional requirements
Structures
Systems
Develop screening tools
54.4(a)(1) Criterion
54.4(a)(2) Criterion
54.4(a)(3) Criterion
DBE Flow Charts
Vital Auxiliaries Tool
FP, EQ, ATWS, SBO, PTS Tools
Is the building a Class 1 structure?
No
Is system/ structure required by the tool?
No
Is system/ structure required by the tool?
No
Is system/ structure required by the tool?
No
Yes
Yes
Yes
Yes
Add Function to Intended Functions List
Add Function to Intended Functions List
Add Function to Intended Functions List
Add Function to Intended Functions List
List of intended functions for SSs
Does the system or structure have an intended function?
Yes
No
SSs within the Scope of License Renewal
No further action required for these SSs

Figure 3-1

The following information is compiled for each SS and entered into a table designated as Table 1, "System/Structure Information:"

- System or structure name;
- Unit number;
- Identification number;
- Brief description, including major components and system interfaces;
- Source document reference (for the description);
- System or structure functional requirement(s); and
- Source document reference (for each functional requirement).

3.3 Screening Tools Preparation

Screening Tools are created during the scoping process in order to add efficiency to the process by allowing the evaluator to review each reference document only once, rather than once for each system. A screening tool is a summary of a source document or documents compiled through research of an event. The tool contains a list of SSCs which respond to the event and their intended functions.

The source documents identified in this section are reviewed against the §54.4 criteria contained in the LR Rule. For each criterion, appropriate information is taken from the source documents and summarized in one or more screening tools. The tools are then used to complete the screening process. Each tool is described below. An example of a portion of a screening tool is provided in Table 3-2.

3.3.1 Tools Addressing §54.4(a)(1) and (2)

10 CFR 54.4(a)(1) and (2) (referred to as §54.4 Criteria 1 and 2) are addressed together in the System Level Scoping process since both of these criteria were used to establish the CCNPP Q-List documentation.

§54.4 Criterion 1

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

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

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

(iii) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines.

§54.4 Criterion 2

(2) All nonsafety-related systems, structures and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraph (a)(1)(i), (ii) or (iii) of this section (i.e., §54.4).

3.3.1.1 DBE Flow Chart Preparation

The CCNPP UFSAR Chapter 14 DBE accident analyses listed below are reviewed. This list contains both design basis accidents and anticipated operational occurrences. No external events are analyzed in Chapter 14 of the CCNPP UFSAR. All structures designed to withstand DBE external events are designated as Class 1 structures at CCNPP, and Class 1 structures are included within the scope of LR (Section 3.4.1.2).

Design Basis Event	Chapter 14 Location
CEA Withdrawal Event	Section 2
Boron Dilution Event	Section 3
Excess Load Event	Section 4
Loss of Load Event	Section 5
Loss of Feedwater Flow Event	Section 6
Excess Feedwater Heat Removal Event	Section 7
RCS Depressurization	Section 8
Loss of Coolant Flow Event	Section 9
Loss of Non-Emergency AC Power	Section 10
CEA Drop Event	Section 11
Asymmetric SG Event	Section 12
CEA Ejection	Section 13
Steam Line Break Event	Section 14
SG Tube Rupture Event	Section 15
Seized Rotor Event	Section 16
Loss of Coolant Accident	Section 17
Fuel Handling Incident	Section 18
Turbine-Generator Overspeed Incident	Section 19
Containment Pressure Response	Section 20
Hydrogen Accumulation in Containment	Section 21
Waste Gas Incident	Section 22
Waste Evaporator Incident	Section 23
Maximum Hypothetical Accident	Section 24
Excess Charging Accident	Section 25
Feed Line Break Event	Section 26

The CCNPP Q-List includes Accident Shutdown Flow Sheets[3] for 17 of the DBEs. Each Accident Shutdown Flow Sheet identifies the CSFs and plant functions supporting CSFs,

[3] The terms "Q-List Accident Shutdown Flow Sheet" and "Vital Auxiliaries Flow Sheets" are used to refer to documentation which already existed as part of the CCNPP Q-List. The terms "DBE Flow Chart" and "Vital Auxiliaries Screening Tool" are used to denote the document created during the scoping process to compile the Q-List information and other specified information.

which are necessary to reach safe shutdown for the DBE identified, maintain fission product boundaries, and prevent offsite releases in excess of established guidelines. These flow sheets also identify the supporting systems (as well as VA systems) which are required to satisfy the associated CSF. The DBE flow charts are a consolidation of Q-List Accident Shutdown Flow Sheets and any additional supporting systems identified as relied on for that accident in UFSAR Chapter 14.

For the eight DBEs which are identified in the UFSAR and are not the subject of Q-List Accident Shutdown Flow Sheets, a DBE flow chart is prepared by the system level scoping process. These DBE Flow Sheets contain the following information depending on the reason that no Q-List Accident Shutdown Flow Sheet was prepared (as documented in Q-List documentation).

Reason Why No Accident Shutdown Flow Sheet is in the Q-List	Information Included in Scoping Results DBE Flow Chart
No active components are relied on to mitigate the event.	Passive components which mitigate the DBE.
No active or Passive components are required to mitigate the event.	A note stating that no active or passive components are required to mitigate the event.
All components relied on for the event are already included in another Accident Flow Sheet.	A note stating that all components required to mitigate the event are included in another DBE Flow Sheet, and specifying which other DBE(s).

The DBE flow charts for the remaining 17 DBEs identify the systems and the functions provided by each of these systems in order to support the CSFs necessary to reach safe shutdown for the specific DBE, maintain the fission product barriers, and prevent offsite releases in excess of established guidelines.

Q-List documentation also contains a specific flow sheet for VAs. Electric power distribution; control air; cooling water; and heating, ventilation, and air conditioning functions for the SR equipment required to respond to each DBE are annotated in the corresponding Q-List Accident Shutdown Flow Sheet. The Q-List Vital Auxiliaries Flow Sheet is a compilation of the systems performing these VA functions for all of the Q-List Accident Shutdown Flow Sheets. The VA screening tool prepared during the system level scoping process duplicates the SSCs listed on the Q-List Vital Auxiliaries Flow Sheet using the SS nomenclature shown in Table 3-1.

All systems and functions identified in the DBE flow charts and the VA screening tool are coded (by shading) to identify the source document(s) (i.e., UFSAR, Q-List Manual, or both).

By relying on the Q-List Accident Shutdown Flow Sheets and Vital Auxiliaries Flow Sheets, all SR SSs are identified, as well as all SSs that could fail and prevent the functioning of SR SSCs. This identification is not limited to first level, second level or any specific level of support equipment. Rather, the scoping is performed consistent with the CCNPP Q-List Design Standard which was developed with the intent of identifying and controlling a similar[4] scope of SSCs to that defined by the first two criteria of §54.4. Therefore, the CCNPP scoping process is consistent with the Commission's intent stated in the SOC to the LR Rule.

An applicant for LR should rely on the plant's CLB, actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those NSR systems, structures, and components that are the initial focus of the LR review. (60 FR 22467)

3.3.2 Tools Addressing §54.4(a)(3)

§54.4 Criterion 3

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

Plant evaluations have been performed to demonstrate compliance with the regulations identified in §54.4(a)(3) (referred to as §54.4 Criterion 3). These evaluations are reviewed to identify SSs that are relied on to mitigate the subject plant event as well as any systems or structures whose failure would result in failure of other equipment to mitigate the particular event. As was the case for Criteria 1 and 2, an SS is listed as within the scope of LR when the mitigation function or support function associated with it is credited in the analysis or evaluation. Mentioning an SS in the analysis or evaluation does not necessarily indicate that the SS contributes to an intended function.

Additionally, if the SS function is identical to a SR function (as identified in the Q-List), then the function need not be repeated on the tools addressing §54.4 Criterion 3. The analyses and evaluations being reviewed in this step are used to identify intended, NSR functions.

3.3.2.1 FP Screening Tool Preparation

The CCNPP UFSAR, FP Program documentation and the CCNPP Interactive Cable Analysis are reviewed to identify the system functions that address the Commission's regulations on FP and the BGE commitments for implementation of those regulations. The identified SSCs, their intended function(s), and the appropriate source documents with revision numbers are summarized in the FP Tool.

[4] The CCNPP Q-List documentation also establishes controls for PAM (Category 1 and 2) equipment. Post-Accident Monitoring equipment satisfies §54.4 Criterion 3, rather than 1 or 2.

3.3.2.2 EQ Screening Tool Preparation

Two tools are produced for this criterion, the EQ tool and the PAM tool.

The Q-List data in the NETD is reviewed to identify items listed as 5049 (items which must meet the requirements of 10 CFR 50.49). A list of the systems containing components designated as EQ is prepared with the Q-List revision number (or date, as appropriate) provided as a reference.

The CCNPP UFSAR is reviewed to identify the systems containing components required for PAM category 1 or 2 variables (as defined in Regulatory Guide 1.97). A PAM System summary table is prepared. It lists each system which is required for PAM, the variable(s) it monitors, and the appropriate source document and revision.

3.3.2.3 PTS Screening Tool Preparation

Since neither CCNPP Unit 1 nor 2 is expected to require an evaluation in accordance with Regulatory Guide 1.154 in order to satisfy 10 CFR 50.61 requirements, no equipment is included within the scope of LR due to the PTS Rule. The PTS Screening Tool is provided in the System Level Scoping Results, but this tool merely notes that no SSCs are relied on for this event. Additionally, the System Level Scoping Results, the component level scoping process, and the component level scoping results for each system include the contingency to implement a PTS scoping criterion, but the results indicate no PTS-related SSCs. If a Regulatory Guide 1.154 evaluation is required at some point in the future, the scoping process would be modified to require incorporating the PTS functions relied on in the 1.154 analysis into the PTS Screening Tool. The Regulatory Guide 1.154 analysis would also trigger an update to the system level and component level scoping results to include the SSCs associated with the 1.154 functions within the scope of LR.

3.3.2.4 ATWS Screening Tool Preparation

The CCNPP UFSAR is reviewed to identify the system functions that address the 10 CFR 50.62 requirements on ATWS. An ATWS Screening Tool is developed. The tool lists the SSCs which are relied on in response to an ATWS event. For each identified SS, the tool lists the intended function(s) provided and the appropriate source documents with the revision number.

3.3.2.5 SBO Screening Tool Preparation

The Station Blackout Analysis is reviewed to identify SSs which are relied on during the "coping duration" phase of an SBO event. An SBO Screening Tool is prepared which lists the SSs relied on in the Station Blackout Analysis, the function(s) that each provides, and the appropriate source documents with revision numbers. The power restoration phase of the Station Blackout Analysis is specifically excluded from review in this criterion since several success paths for restoring power after an SBO are already screened as within the scope of LR due to Criterion 1 (SR).

3.4 SS Scoping

The scoping process is implemented for each SS by reviewing each of the screening tools generated in Section 3.3 and developing a System Level Scoping Results Table. (An example page of the System Level Scoping Results Table is shown in Table 3-3.) For the DBE tools and the VA tools, the function(s) being provided are noted on the System Level Scoping Results Table. Since the events summarized by the tools address the requirements of the §54.4 criteria, inclusion of an SS in a tool indicates that it is within the scope of LR. It is important to note that all intended functions are identified for each SS during the scoping process. Identifying only one intended function would be sufficient to make an in-scope determination; however, the list of all intended functions for an SS facilitates the component level scoping task. This step is repeated for each SS so that an in-scope determination is made for each.

3.4.1 Criteria 1 and 2 -- SR and SR Support SSs

3.4.1.1 DBE Flow Charts and VA Screening Tool

The DBE flow charts and the VA screening tool, (see Section 3.3.1.1), are used to identify those SSs whose functions support the CSFs for a DBE, or whose failure would prevent performance of the CSFs. Systems and structures listed in one or more of the DBE flow charts or the VA screening tool are included in the System Level Scoping Results Table under Criteria 1 and 2. For each SS listed in the results table, all applicable DBEs are identified along with the functions that the SS provides for each DBE. The source document references and revision numbers are not included in the scoping results table since this information can be found in each DBE flow chart or the VA screening tool.

3.4.1.2 Class 1 Structures

For all listed structures, the UFSAR Section 5 and Q-List Design Standard are reviewed to determine whether the structure or a portion thereof is designated as SR, Class 1. At CCNPP, all Class 1 structures (buildings) are designated as SR; therefore all Class 1 structures are screened as within the scope of LR. The results of this scoping step are incorporated, along with the appropriate source document references and revision numbers or dates, into the System Level Scoping Results Table for each of the structures.

3.4.2 Criterion 3 -- SSs Relied On in Plant Safety Evaluations

The corresponding screening tools (see Section 3.3.2) are used to identify the following SSs:

1) Those that perform functions designated as required for FP;

2) Those which contain components identified as EQ or PAM;

3) Those whose functions are relied on in plant event evaluations for ATWS, SBO, and PTS; or

4) Any combination of these factors.

If one of the SSs being screened is listed in any of these tools, it satisfies Criterion 3. The results of this scoping step are incorporated into the System Level Scoping Results Table for each of the SSs. The source document references and revision numbers are not included in the scoping results table since this information can be found in each screening tool.

3.5 Results

As a result of system level scoping, SSs are assigned to one of two categories: (1) those that are within the scope of LR; and (2) those that are not. Systems and structures that belong to category (1) require further scoping in preparation for the IPA process and proceed to component level scoping, as described in Section 4.0.

TABLE 3-1

CCNPP SYSTEMS AND STRUCTURES

1	Switchyard (500 kV) & Switchyard DC
2	Electrical 125VDC Distribution
3	Electrical 13kV Transformers & Buses
4	Electrical 4 kV Transformers & Buses
5	Electrical 480V Transformers & Buses
6	Electrical 480V Motor Control Centers
7	Electrical 13kV Unit Buses
8	Well and Pretreated Water
9	Intake Structure
11	Service Water Cooling
12	Saltwater Cooling
13	FP
14	Transformer Deluge
15	CCW
16	Electrical 250VDC
17	Instrument AC
18	Vital Instrument AC
19	Compressed Air
20	Data Acquisition Computer
21	Domestic Water
22	Makeup Demineralizer
23	Diesel Oil
24	Emergency Diesel Generator
25	Access Control Area Ventilation
26	Annunciation
27	Auxiliary SGs
28	Auxiliary Steam
29	Plant Heating
30	Control Room Heating, Ventilation & Air Conditioning
31	Meteorology Tower & Miscellaneous Computers
32	Auxiliary Building and Radwaste Heating & Ventilation
33	Turbine Building Ventilation
34	Condensate Precoat Filter
35	Chemical Additions - Turbine
36	AFW
37	Demineralized Water and Condensate Storage
38	Sampling System
39	Condensate Polishing Demineralizer
41	Chemical and Volume Control
42	Circulating Water
43	Condenser Air Removal
44	Condensate
45	Feedwater
46	Extraction Steam
47	Feedwater Heater Drains and Vents
48	Engineering Safety Feature Actuation
49	Simulator Computer
50	Solid Waste Disposal
51	Plant Water
52	Safety Injection
53	Plant Drains
55	CEA Drive Mechanism & Electrical
56	Reactor Regulating
57	Technical Support Center Computer
58	Reactor Protective
59	Primary Containment
60	Primary Containment Heating & Ventilation
61	Containment Spray
62	Control Boards
63	Cathodic Protection
64	Reactor Coolant
65	Seismic
66	Cavity Cooling
67	Spent Fuel Pool Cooling
68	Spent Fuel Storage
69	Waste Gas
70	Refueling Pool
71	Liquid Waste
72	Sewage Treatment Plant
73	Hydrogen Recombiner
74	Nitrogen and Hydrogen
75	Low Voltage DC Control Power
76	Secondary Sample
77/79	Area/Process Radiation Monitoring
78	Nuclear Instrumentation
80	New Fuel Storage and Elevator
81	Fuel Handling
83	Main Steam
84	Reactor Vessel Internal
85	Plant Access and Surveillance
86	Power Plant Security
87	Unit Transformers
88	Visitor Center Security
89	Emergency Operations Facility Security
90	Service Building & Outlying Building Heating, Ventilation & Air Conditioning
91	Lube Oil Storage
92	Gland Steam
93	Main Turbine
94	Plant Computer

TABLE 3-1

CCNPP SYSTEMS AND STRUCTURES (Continued)

95 Carbon Dioxide
96 Fire and Smoke Detection
97 Lighting and Power Receptacle
98 Main Generator and Excitation
99 Cranes/Test Equipment
100 Plant Communications
101 Dry Fuel Storage
102 Plant Areas
103 Emergency Diesel Generator Building Heating, Ventilation & Air Conditioning (2)
104 Lubrication
105 Weight Testing Wire Ropes & Slings (3)
106 Ladders and Gratings (3)
107 Roads
108 Docks and Marine Related Structures
109 Shop Equipment (3)
110 Manual Valve Components (3)
111 Materials Processing Facility (3)

Additional Structures

Auxiliary Building.
Condensate Storage Tank No. 12 Enclosure
Domestic Water Treatment Plant
Engine Generator House
Equipment Hatch Access Building. No. 1
Equipment Hatch Access Building. No. 2
FP Pump House
Fuel Assemblies
Fuel Oil Storage Tank No. 21 Building.
Hydrogen Storage Pad
Modifications Mechanical Lock-up (No. 3)
Modifications Mechanical Lock-up (No. 4)
Oil Interceptor Pit
Service Building [B-3]
South Service Building.
Switchgear Structure
Transformer Foundations
Turbine Building
Waste Water Treatment Building.
Well Observation Building
Well Water Pump House
Independent Spent Fuel Storage Installation (4)
Diesel Generator Building 1 (2)
Diesel Generator Building 2 (2)

NOTES:

1. System listing is from Attachment 6 of DS-032, “Control of the Equipment Technical Databases”
2. Systems and structures associated with the new diesel generator installation do not become part of the CCNPP licensing basis until after the 1996 refueling outage, and therefore, are not yet included in the scoping results.
3. These systems were not included as systems in the LR scoping process because they are portable equipment or because they are already included in other systems.
4. The Independent Spent Fuel Storage Installation is not licensed under 10 CFR Part 50 and, therefore, is not in the scope of this LRA.

TABLE 3-2 **Revision 4**
Post-Accident Monitoring Screening Tool **(Example)**

Reference 1 - Calvert Cliffs Nuclear Power Plant, Units 1 & 2, Updated Final Safety Analysis Report (UFSAR), Section 7.5.8

Reference 2 - Calvert Cliffs Nuclear Power Plant, NUCLEIS Equipment Database

SYSTEM/ STRUCTURE	SYSTEM ID No.	MONITORING VARIABLE(S) / FUNCTION(S)
Electrical 125VDC Distribution	2	• Status of standby power (voltage, current)
Electrical 4kV Transformers and Buses	4	• Status of standby power (voltage, current)
Electrical 480V Transformers and Buses	5	• Status of standby power (voltage, current)
Service Water	11	• Service water pump status (motor current) • Containment cooler cooling water flow
Saltwater	12	• Saltwater pump status (motor current)
CCW	15	• CCW heat exchanger outlet temperature • CCW to/from reactor coolant pumps containment isolation valve position • CCW pump discharge pressure (for flow indication) • CCW pump status (motor current)
Vital Instrument AC	18	• Status of standby power (voltage)
Compressed Air	19	• Instrument air containment isolation valve position indication
Data Acquisition Computer	20	• Provide fault protection for Instrumentation & Controls loops
Emergency Diesel Generator	24	• Status of standby power (voltage, current, VAR, frequency)
Auxiliary Building & Radwaste Heating & Ventilation	32	• Fuel pool exhaust fan damper position
AFW	36	• AFW flow to SGs • Motor-driven AFW pump status (motor current) • Condensate storage tank 12 level
Sampling System	38	• Containment hydrogen concentration

TABLE 3-3

LCM-12 Revision 5

BGE LCM PROGRAM
TABLE 2
SYSTEM LEVEL SCOPING RESULTS (EXAMPLE) Revision 4

			CRITERIA 1 & 2					CRITERION 3						
System/Structure	Unit	ID	Req'd for DBE	DBE Plant Function(s)	Q	Class I or SR-1M	Class I or SR-1M Reference	PAM	FP	ATWS	SBO	PTS	EQ	In Scope Yes/No
Switchyard (500 kV) and Switchyard DC	1&2	1	No	None	No	N/A	N/A	No	No	No	No	No	No	No
Electrical 125 VDC Distribution	1&2	2	VA	VA for Chemical & Volume Control System VA for AFW VA for Main Steam VA for Containment Spray VA for Primary Containment Heating & Ventilation VA for Emergency Diesel Generators VA for 4KV Transformers & Buses VA for 480V Motor Control Centers VA for 480V Bus System VA for Vital Instrument AC VA for Service Water VA for CCW VA for Saltwater Cooling VA for Control Room Heating, Ventilation & Air Conditioning VA for Auxiliary Building & Radwaste Heating & Ventilation VA for RCS VA for Emergency Safety Features Actuation System Load Shedding VA for Chemical & Volume Control System (Core Flush)	No	N/A	N/A	Yes	Yes	No	No	No	No	Yes
Electrical 13kV Transformers and Buses	1&2	3	No	None	No	N/A	N/A	No	No	No	No	No	No	No
Electrical 4kV Transformers and Buses	1&2	4	VA	VA for AFW VA for Safety Injection VA for Containment Spray VA for 480V Bus VA for 480V Motor Control Centers VA for Service Water VA for SW Cooling VA for Emergency Safety Features Actuation System Load Shedding	No	N/A	N/A	Yes	Yes	No	No	No	No	Yes

4.0 COMPONENT LEVEL SCOPING

Component level scoping is the second and final task needed to determine the scope of SSCs to be addressed by the IPA for aging. The criteria for including components within the scope of LR are the same as those for SSs and are defined in §54.4.

The component level scoping process is conducted one system at a time for each SS designated as within the scope of LR. The scoping is accomplished through application of either the component level scoping process for systems, which is illustrated in Figure 4-1 and discussed in Section 4.1, or the component level scoping process for structures, illustrated in Figure 4-2 and discussed in Section 4.2. Section 4.3 describes several variations to the standard component level scoping process used in specific instances. Section 4.4 describes how the results are documented.

4.1 Component Level Scoping for Systems

The component level scoping process for systems is implemented by systematically reviewing the intended functions of the system (determined by the system level scoping process) to determine which system components contribute to the performance of the functions. Components are designated as within the scope of LR if they are required for their system to perform an intended function.

The component level scoping process for systems is divided into several distinct steps. Each step is discussed below.

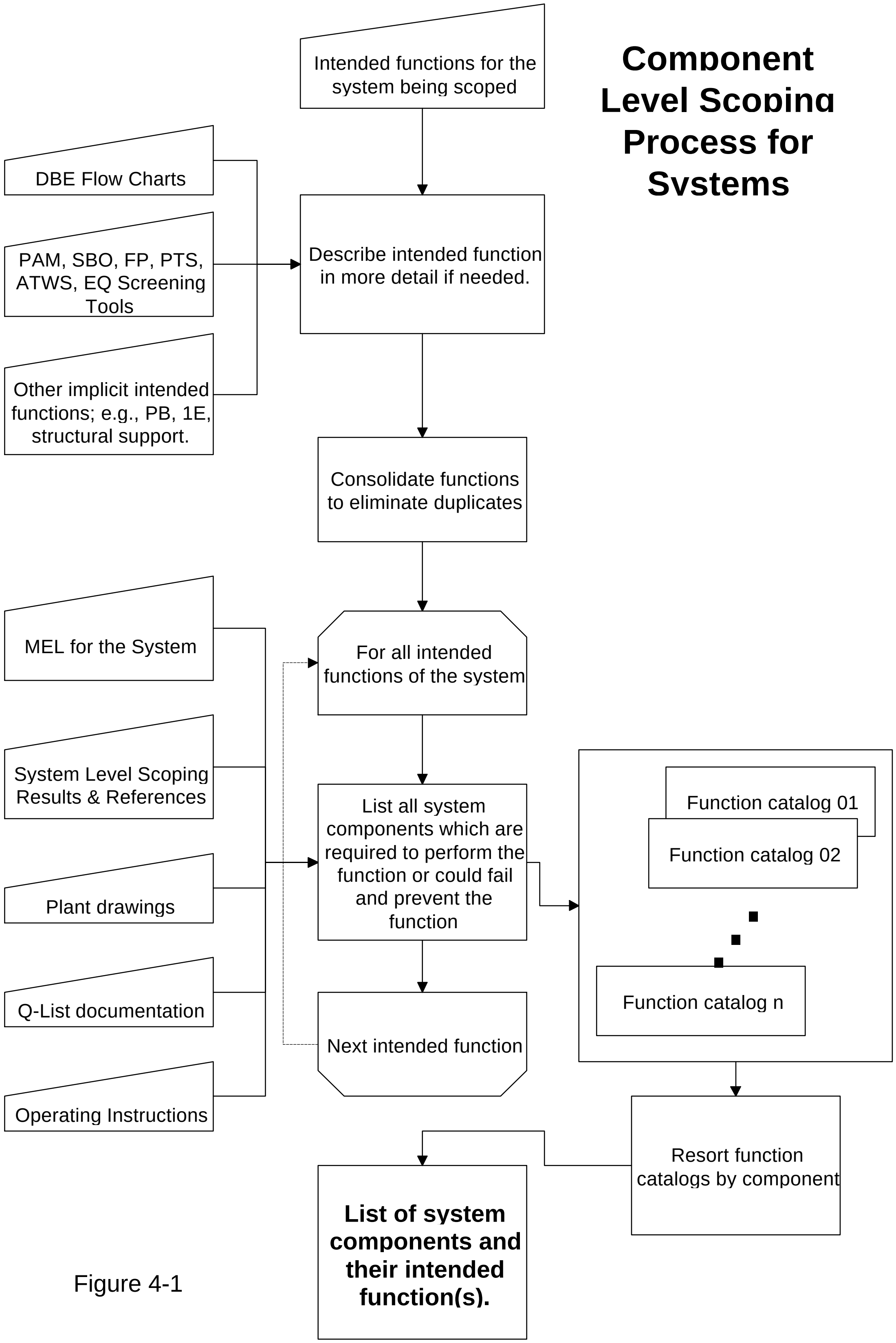
Component Level Scoping Process for Systems
Intended functions for the system being scoped
DBE Flow Charts
PAM, SBO, FP, PTS, ATWS, EQ Screening Tools
Other implicit intended functions; e.g., PB, 1E, structural support.
Describe intended function in more detail if needed.
Consolidate functions to eliminate duplicates
MEL for the System
System Level Scoping Results & References
Plant drawings
Q-List documentation
Operating Instructions
For all intended functions of the system
List all system components which are required to perform the function or could fail and prevent the function
Next intended function
Function catalog 01
Function catalog 02
Function catalog n
Resort function catalogs by component
List of system components and their intended function(s).

Figure 4-1

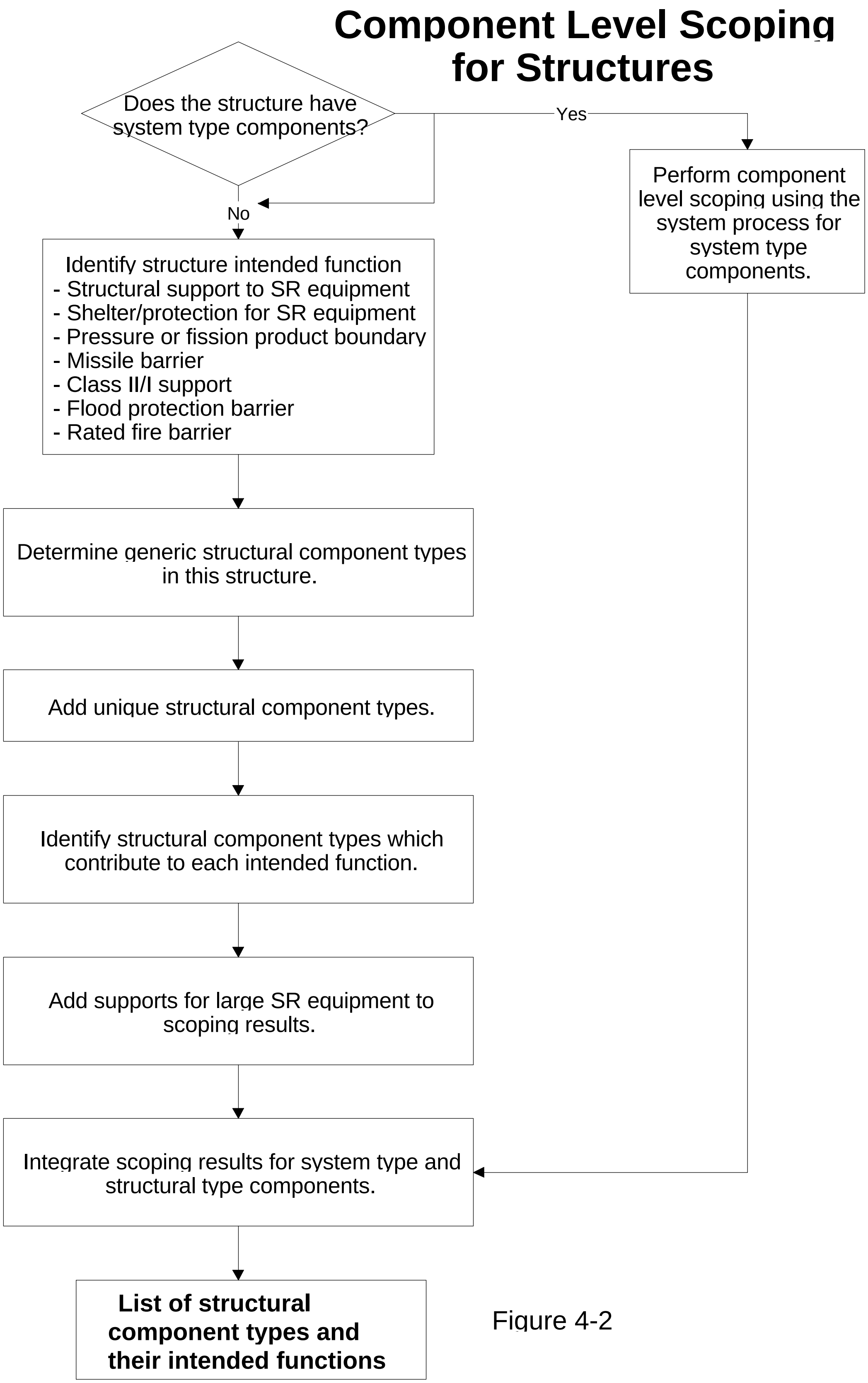
Component Level Scoping for Structures
Does the structure have system type components?
Yes
No
Perform component level scoping using the system process for system type components.
Identify structure intended function
- Structural support to SR equipment
- Shelter/protection for SR equipment
- Pressure or fission product boundary
- Missile barrier
- Class II/I support
- Flood protection barrier
- Rated fire barrier
Determine generic structural component types in this structure.
Add unique structural component types.
Identify structural component types which contribute to each intended function.
Add supports for large SR equipment to scoping results.
Integrate scoping results for system type and structural type components.
List of structural component types and their intended functions

Figure 4-2

4.1.1 Identification of Detailed System Functions

The purpose of this step of the scoping process is to create a detailed list of the intended functions associated with the system being scoped. The list is compiled in a System Functions Table using the System and Structure Scoping Results, Q-List documentation, plant drawings, the UFSAR, System Descriptions and other references. It should be noted that these intended functions are required to be performed under a variety of design conditions in accordance with the CLB.

The System and Structure Scoping Results contain screening tools which associate intended functions with individual systems. The first substep of creating the detailed function list is to review all of the screening tools and, in the System Functions Table, record the intended functions of the system being scoped.

The CCNPP Q-List Design Standard (Table 2-1 Reference 8) is the site reference which governs what components are controlled as SR, SR support, or other miscellaneous category equipment. To ensure consistency with the Q-List documentation, the LCMEVAL software application is used to compile a listing of all Q-List categories which are associated with any components in the system being scoped (Q-List Criteria listing). This listing represents the Q-List related functions associated with the system being scoped. The following Q-List categories correspond to §54.4 criteria as described below:

Q-List Flow Sheets -

These flow sheets identify components which are relied on to respond to UFSAR Chapter 14 DBEs or serve as VA to SR equipment. Criteria 1 and 2.

PB - The category of PB mechanical items which maintain the system PB of the RCS, maintain the radiological boundary to prevent exceeding 10 CFR Part 100 limits, or maintain safety system boundary to limit system leakage. Criteria 1 and 2. (Criterion 2 because PB includes the components needed to maintain the PB of fluid systems which are not fission product boundary fluid systems.)

1E - The category of electrical equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or otherwise are essential in preventing significant release of radioactive material to the environment. Criteria 1 and 2. (Criterion 2 because 1E includes electrical isolation devices whose sole "intended" function is to prevent an electrical fault in a NSR portion of the system from affecting the SR functions of the system.)

1M - The category of mechanical equipment that is essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or otherwise are essential in preventing significant release of radioactive material to the environment. Criterion 1.

PAM - Post-accident monitoring category of instrumentation used to assess the environs and plant conditions during and following an accident. Criterion 3, subset of EQ.

5049 - This category identifies items which are required to be environmentally qualified to the requirements of 10 CFR 50.49. Criterion 3.

CLS1 - The category for those SSCs, including their foundations and supports that are designed to remain functional in the safe shutdown earthquake, as defined in 10 CFR Part 100. Criterion 2. ("CLS1" is the Q-List Manual designation for items referred to as "Seismic Category 1" or "Class 1" elsewhere in this methodology.)

Q - The category for any item specified by the Q-List Committee as requiring the same level of quality assurance as provided for SR items. (Criterion to be determined during scoping.)

SBO - The category of equipment required to withstand and recover from an SBO event. Criterion 3.

After producing the Q-List Criteria Listing for the system being scoped, this list is consolidated with the functions already listed in the System Functions Table to finalize the detailed functions listing for the system. The Q-List does not contain information related to several of the regulated events in §54.4 Criterion 3. Therefore, for the categories shown below, no consolidation with Q-List-related functions is possible. The associated screening tools and their references are used to validate the detailed system function(s) for these criteria.

FP - The functions required by 10 CFR 50.48 for FP and safe shutdown after fire.

ATWS - The functions required by 10 CFR 50.62 to provide diverse scram and diverse turbine trip capability during an ATWS event.

PTS - The functions required by 10 CFR 50.61 to provide protection during a PTS event.

The final step of intended function identification is to eliminate redundant functions. Functions enveloped by another function or identical to another function are consolidated. The enveloping function is designated as the "Parent" function, while the enveloped function is the "Child" function. The child function is retained on the System Functions Table in order to be able to trace the steps of the process which created the table. Parent functions and functions for which no consolidation is possible are assigned a unique identification number (Function ID) to facilitate subsequent steps in the scoping process. (For the remainder of this methodology, the term "intended function" refers to a parent function unless otherwise specified.)

4.1.2 The MEL

To ensure that all components in the plant are scoped with one and only one system, the site MEL is used to provide the equipment list for the component level scoping task for each system. This list is the portion of the NETD which contains all equipment for a given system.

In developing the NETD, conventions were established for determining the boundaries between systems. These conventions provided the guidance for determining which system each component in the IPA would be assigned to. Several example conventions are listed below. The complete system boundary guidelines are contained in the site design standard for controlling equipment technical databases.

- Heat exchangers are assigned to the load system.
- Electrical components are assigned to load system from the load side of the circuit breaker.
- Sensors are assigned to the system in which they sense. Actuators are assigned to the system in which the actuation takes place.
- Transformers are assigned to the lower voltage system.

As each scoping task is begun, the LCMEVAL software application is loaded from the NETD with the MEL for the system to be scoped. Each of the components on this list must be dispositioned during the scoping task as either contributing to an intended function listed in the System Functions Table or not needed for any of these functions.

4.1.3 Development of Function Catalogs

The next step in the component level scoping process for systems is to determine, for each intended function, which components from the system MEL are needed to perform the function. A list of components for each function is called the function catalog.

In order to determine the relationship between a given function and the components contributing to the function, Q-List documentation, UFSAR, Technical Specifications, system screening tools and references associated with the screening tools are used.

The active components associated with mitigating the consequences of individual DBEs or providing VA functions to SR equipment are listed in the plant Q-List documentation along with a reference to their safety function(s). Consequently, whenever a System Functions Table contains a DBE function or a VA function, the Q-List provides a direct input to the scoping process for determining which components of the given system contribute to §54.4 Criterion 1 and 2.

The Q-List documentation also includes Piping and Instrumentation Drawings which are coded to reflect the portions of each system which passively support the system PB function for that portion of the system relied on to mitigate DBEs. Whenever the system function table contains DBE functions and the MEL contains mechanical PB components, a PB function catalog is created for the system. For each component in the MEL, a determination is made, based on these Q-List-coded Piping and Instrumentation Drawings, whether the component is within the annotated PB portion of the drawing. If so, the component is included in the PB catalog. Those passive components which perform in exactly the same manner for any intended function are not included in catalogs associated with other functions in order to avoid redundancy.

The Q-List documentation also contains listings which associate specific components to PAM and EQ functions. This listing is used as a direct input to the scoping process whenever PAM or EQ functions are contained in the system function table. Based on this input, a function catalog is created for both PAM and EQ. In order to be more specific regarding which components actually contribute to providing each of the required PAM indications, plant drawings and the BGE UFSAR are consulted. In addition to the component listing, the PAM catalog contains a letter in the notes column to specify which PAM indication is associated with each component.

The Q-List documentation contains a listing which associates specific components to the Class 1 function. This listing is used as a direct input to the scoping process whenever there is a Class 1 function in the System Functions Table. Based on this input, a function catalog is created for Class 1. This catalog normally contains EPs and other enclosure devices which contain SR equipment but have no explicit active safety function.

Many electrical and a few mechanical components are identified in the Q-List Manual as 1E only or 1M only. Such components perform the same function in support of a number of important events but are not actually associated with any particular DBE in the Q-List documentation. When a system contains components that are SR and designated only as 1E or 1M, a separate function catalog is created to contain these components.

The NETD contains a field which associates specific components with the Station Blackout Analysis. This SBO designation is used as an input to scoping for SBO and further review is conducted during the IPA process as described below:

- The NETD SBO designation is assigned to components <u>mentioned</u> in the Station Blackout Analysis. Other components which must function so that these "mentioned" components can perform their SBO function are identified and added to the SBO function catalogs.
- Much of the equipment mentioned in the Station Blackout Analysis is mentioned because it is secured at the start of an SBO event or is used when restoring power after the end of the event. These components do not contribute to any SBO functions in the SBO tool, and therefore are not included within the scope of LR. These components are not included in the SBO function catalogs.

When the process is complete, the SBO function catalog or catalogs contain all of the system components which contribute to each intended SBO function.

The equipment in the system MEL which is designated in Q-List documentation as SR category "Q" also requires further analysis during the scoping process. The documentation which supports the classification of these type components is reviewed to determine why the equipment has been designated as SR category Q. If the SR-Q components perform an intended function, the components are included in the corresponding function catalog. Otherwise, the components are categorized as not within the scope of LR.

For the ATWS, PTS and DBE functions contained in the System Functions Table, one function catalog is created for each listed function. The reference information used to create the associated screening tool is consulted, as needed, along with plant drawings to determine exactly which system components contribute to the performance of each listed function. Components which perform exactly the same function to support one of these criteria as they perform to support a SR function, are not repeated again in these function catalogs to avoid redundancy. For example, if a pump is required to start during a severe fire to ensure plant shutdown and the same pump must start to provide cooling water to SR equipment to mitigate the consequences of a DBE, that pump would not be repeated in the FP function catalog.

All of the function catalogs discussed above are created using the LCMEVAL software system which contains data loaded directly from a controlled site database (NETD) where possible. For the functions where no source of direct component data is available in software format, the individual components are entered one at a time into the function catalog. The software ensures that only valid components (i.e., in the MEL for the system being scoped) are added to function catalogs. It also facilitates the recording of reference documents which justify that a component supports a given function.

4.1.4 Generation of Scoping Results Table

In the next step of the component level scoping process for systems, the function catalogs that were developed in Section 4.1.3 are resorted by LCMEVAL to produce a list of system components and the intended functions associated with each component. Components not associated with any intended function are designated as not within the scope of LR by the LCMEVAL software system. The table of in-scope components and the intended functions that they contribute to is designated as the Component Level Scoping Results Table.

4.2 Component Level Scoping for Structures

The component level scoping process described above for systems can also be applied to structures. However, this process is somewhat different because of the unique features of structures and how they are documented on site. As with systems, the scoping process is implemented by determining which structural components are required for the performance of the intended functions of the structure. Details of the methodology implementing the structural component scoping are presented below.

4.2.1 Unique Identifiers for Structural Components

The components of structures have not generally been identified and listed in an MEL. Consequently, the component level scoping for structures cannot use a comprehensive equipment listing as an input.

For certain site structures, such as the containment, specific component types have been identified in the site equipment database. For these structures, a partial MEL is available and the structural component scoping process is divided into two parts:

1) The components documented in an MEL for the structure are scoped using the process described in Section 4.1, above, if it is determined that they do not perform a structural-type function. Components such as the containment personnel hatch, the personnel hatch limit switches and the containment penetrations are scoped using this process because they are designated as components of the containment system in the NETD.

2) The remaining portions of the structure such as beams, columns and walls are scoped using the process described in this section.

The results are then merged when both procedures are complete to present a combined scoping result for the entire structure.

4.2.2 Function Identification

The SS scoping process identifies some structures as within the scope of LR because they are designed to Class 1 criteria or because they are required for DBE purposes. Unlike the scoping results for systems, the Class 1 structure in-scope determination does not actually reveal a great deal about the intended functions of the structure. Therefore, during the component level scoping, the evaluator reviews Chapters 5 and 5A of the UFSAR to determine specific structure design basis information such as which external events the structure is designed to withstand, and which structural components contribute to these intended functions.

By their nature, structures perform mostly passive functions and are constructed in accordance with predetermined design requirements. Therefore, civil engineers experienced with nuclear plant structures determined that a structure, or components of the structure, are designed to perform one or more of the following functions in support of the §54.4 criteria:

1. Provide structural and/or functional support to SR equipment;
2. Provide shelter/protection to SR equipment. (This function includes radiation protection for EQ equipment and high energy line break-related protection equipment.);
3. Serve as a PB or a fission product retention barrier to protect public health and safety in the event of any postulated DBEs;
4. Serve as a missile barrier (internal or external);
5. Provide structural and/or functional support to NSR equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions (Example: seismic Category II over I design considerations);
6. Provide flood protection barrier (internal[5] flooding event); and
7. Provide a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.

This listing allows an evaluator with a specific civil engineering background to determine which of the generic structure functions apply to the structure being evaluated without being an expert on DBEs.

Functions 1-4 are associated with Class 1 structures. Class 1 design requirements are the structure level equivalent of SR components specified in §54.4 Criterion 1. In a similar fashion, functions 5 and 6 apply to non-Class 1 structural components which could, if they

[5] External flooding events were considered during the design process for CCNPP structures. It was determined that a probable maximum hurricane would cause the worst-case flooding conditions at the site. The resulting surge and wave action was analyzed as the basis of plant flood protection. The effects of possible wave action were studied using a hydraulic model.

fail, prevent a SR function from occurring. This is the structural equivalent for §54.4 Criterion 2. Function 7 is the equivalent for the portion of §54.4 Criterion 3 which is applicable to structures.

The applicability of each function to the structure is determined by a review of various source documents. If the structure is a Class 1 structure, the UFSAR and the System and Structure Scoping Results must be referenced to determine which of functions 1-4 apply. The applicability of functions 5 and 6 to the structure being scoped cannot be made based only on the UFSAR and the System and Structure Scoping Results. Therefore, the determination of the applicability of these criteria to the structure is deferred until Section 4.2.4. To determine whether the structure being evaluated performs function 7 (DBE), the System and Structure Scoping Results are consulted.

Regardless of their applicability to the structure being evaluated, the seven functions are assigned generic ID numbers that can be used with any structure being scoped. Therefore, the Structure Intended Functions Table has the same basic format for every structure. The functions that apply to the structure are identified by indicating "YES" in the "Applicable to This Structure?" column of the Structure Intended Functions Table.

4.2.3 Structural Component Type Listing for the Structure

In the structural component scoping process, components that are structural in nature are not uniquely identified during the scoping process. For example, each wall in the structure is not identified, named, and listed. Rather than using an MEL of named structural components, the scoping is conducted on a generic listing of structural component types. This generic list was developed by experts in the field of nuclear Class 1 structures. The generic list started with structural component types contained in the Containment Industry Technical Report and the Class 1 Structures Industry Technical Report. Other structural component types were added to the list to ensure completeness. (e.g., The Industry Technical Reports considered only SR functions. Therefore, several fire- and flooding-related component types were not considered in these reports.)

The evaluator uses this generic component listing and determines which of the component types on the list are actually contained in the structure being scoped. This step is performed by reviewing plant architectural drawings and identifying the specific structural types. Additionally, any structural component types which are unique to the particular structure being scoped, such as the prestressed tendons in the containment and the sluice gates in the intake structure, are noted. These unique structural component types are then added to the list of applicable structural component types. This list serves as the equivalent of an MEL for structural component scoping task.

4.2.4 Structural Components Which Contribute to Intended Functions

This section describes the process used to determine which component types of a structure contribute to the intended functions which the structure performs. For every function listed in the Structure Intended Functions Table that has a "YES" in its "Applicable to This Structure?" column, a review is made of the UFSAR, the Q-List Manual, or the System and Structure Scoping Results (including documents referenced by these results). The component types which contribute to each intended function are recorded on the "Structural Components Which Contribute to Intended Functions" table.

Additionally, the supports for large SR equipment within the structure are identified by reviewing a listing of the SR equipment installed in the structure that might affect the design of the structure (such as tanks, heat exchangers, or vessels filled with fluid and pumps which require a pedestal as a foundation.). These SR equipment supports are also included in the "Structural Components Which Contribute to Intended Functions" table.

Q-List documentation and the Flooding Design Guidelines Manual are reviewed to determine if structural component types in the structure being scoped are relied on to contribute to the functions of providing structural and/or functional support to NSR equipment whose failure could prevent satisfactory accomplishment of any of the required SR functions or providing flood protection barriers. If structural component types in the structure being scoped are determined to contribute to these functions, then this information is captured by recording "YES" in the "Applicable to This Structure?" column of the Structural Intended Functions Table. The components that contribute to these functions are then recorded on the "Structural Components Which Contribute to Intended Functions" table, with a reference to the appropriate intended structure function.

When completed, the “Structural Components which contribute to Intended Functions” table provides the correlation between component types in the structure and their intended function(s). Each component type necessary for an intended function is designated as within the scope of LR.

4.3 Commodity Evaluations that Include Scoping Sections

For certain systems or groups of components, an alternate IPA process was chosen to accomplish the same results as the process described in the first six sections of this methodology. Each of these situations, where commodity approaches were chosen, are shown in Table 4-1, and described in more detail in Section 7 of this methodology. For two of the commodity evaluations, the scoping and pre-evaluation steps are performed using the techniques described in Sections 3 and 4. In the other four commodity evaluation processes, the revised approach replaces the component level scoping, pre-evaluation and AMR. Therefore, for the systems covered by these commodity evaluations, the description of the component level scoping is included in Section 7.

TABLE 4-1

Commodity Evaluation	Scoping Part of Commodity Evaluation?
EPs & Related Equipment	No
ILs	No
Cables	Yes
Cranes and Fuel Handling Equipment	Yes
Component Supports	Yes
FP Systems	Yes

4.4 Results

As a result of the component level scoping process, components are assigned to one of two categories: (1) those that are within the scope of LR; and (2) those that are not. Only components that are within the scope of LR are included in the IPA process. These components proceed to the pre-evaluation task introduced in the next section of this methodology.

5.0 PRE-EVALUATION

This section describes the Pre-Evaluation task. The purpose of this task is to determine which plant SCs are "subject to AMR" in the IPA process.

The Pre-Evaluation task is performed on a system-by-system or structure-by-structure basis (except for equipment covered by the commodity evaluations which replace the entire IPA process, as described in Section 4.3). The description provided in Sections 5.1 through 5.3 of the methodology applies primarily to systems. Section 5.4 describes the differences in the process as it is applied to structures.

The input to this task is the results of the component level scoping task, described in Section 4, for the system being evaluated. These results consist of the intended functions of the system or structure being evaluated and a designation of which portions of the system or structure contribute to the intended functions. From these inputs, the criteria in the LR Rule for "SCs subject to AMR" are applied to determine which SCs in the system or structure must be further evaluated for the effects of aging. The SCs or groups of SCs determined not to be subject to AMR require no further evaluation in the IPA process.

The output of the Pre-Evaluation task is the list of SCs which need to be evaluated further for the effects of aging in the AMR task.

The Pre-Evaluation task is governed by §54.21(a)(1) of the LR Rule.

> *54.21(a)(1) For those systems and structures within the scope of this part, as delineated in §54.4, identify and list those structures and components subject to an AMR. Structures and components subject to an aging management review shall encompass those structures and components --*

(i) *That perform an intended function, as described in §54.4 without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, pressure retaining boundaries, component supports, reactor coolant pressure boundaries, the reactor vessel, core support structures, containment, seismic category I structures, electrical cables and connections, and electrical penetrations, excluding but not limited to, pumps (except casing), valves (except body), motors, batteries, relays, breakers, and transistors; and*

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

Figure 5-1 provides a flow chart of the Pre-Evaluation task.

Pre-Evaluation Process

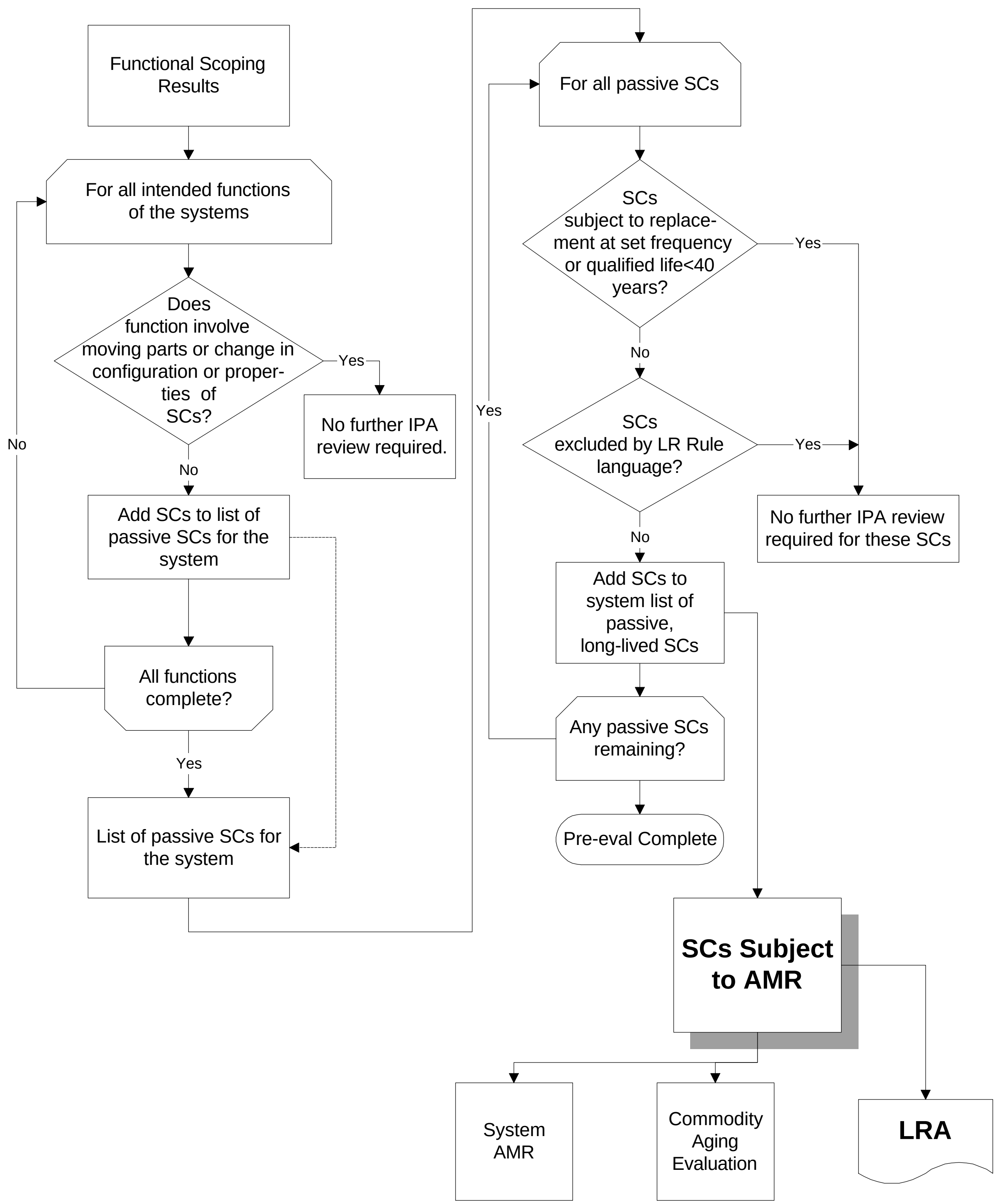

Figure 5-1

5.1 Categorize Intended System Functions as Active or Passive

The first step of the Pre-Evaluation task is to review the list of intended functions for the system being evaluated and characterize each as either active or passive. When a function is determined to be passive, all components which contribute to the passive function are categorized as passive components, even though some of these components may also contribute to an active function. If such components are determined to be subject to AMR, the subsequent AMR task considers only the effects of aging on the passive intended function to which these components contribute. The components' contribution to active functions need not be considered in this evaluation.

5.1.1 Passive Functions

Passive functions are those which require no moving parts or change in SC configuration or properties to carry out the requirements of the function. Such functions generally do not result in plant parameters changing in a measurable manner during normal plant operations. Examples of passive functions are listed below:

- Maintain the pressure-retaining boundary of a fluid system.
- Provide structural support or shelter to equipment.
- Provide missile protection.
- Provide shielding against radiation.
- Provide shielding against high energy line breaks.
- Provide flood protection.
- Prevent or isolate faults in an electrical circuit when such protection or isolation does not involve moving parts or a change in properties or configuration. (e.g., cable insulation).

Any function which is determined to be passive is evaluated in Section 5.2.

5.1.2 Active Functions

Active functions require moving parts or a change in SC properties or configuration to carry out the intended function. For such functions, plant parameters change in a measurable manner during normal plant operation. Performance of this equipment may be assessed by observing, measuring or trending these parameters. Examples of active functions are:

- Provide required flow to a heat exchanger.
- Provide electrical signals to a device.
- Provide electrical power to a bus or load.
- Provide indication of a plant condition.
- Remove decay heat.
- Provide fault isolation where moving parts or a change in properties or configuration is involved. (e.g., circuit breakers, fuses)

Active functions require no further evaluation in the IPA process. Any components which contribute to active intended functions would not be included in the list of SCs subject to AMR, unless warranted by their contribution to other intended functions which are passive.

5.2 Determine Whether Components Are Long-Lived or Short-Lived

In this step of the Pre-Evaluation task, all passive SCs are reviewed to determine if they are subject to replacement based on qualified life or specified time period. Structures and components which are not subject to such replacement are classified as long-lived.

Replacement programs may be based on vendor recommendations, plant experience, or any means which establish a specific replacement frequency. Often, replacement based on qualified life will also be replacement at a specific time period (i.e., the time period dictated by the qualified life). However, in some instances the qualified life of an SC may be based on variables other than calendar time. In either case (calendar time replacement or qualified life replacement), the SCs subject to such replacement would not be included in the list of SCs subject to AMR.

The remaining components which contribute to the passive function will be subject to AMR unless the component type has been specifically excluded from the review by the language of the Rule.

5.3 Assignment of System Components to Commodity Evaluations

As discussed in Section 4.3, there are several categories of equipment which are more efficiently evaluated across system boundaries as members of commodity groups. Commodity groups are components which are present in a number of systems, but which perform the same function regardless of the system to which they are assigned. Commodities such as cables were not scoped as part of a specific system because these components are not assigned to systems in the CCNPP equipment database. As will be discussed in Section 7 of this methodology, the commodity evaluation for these components covers the entire IPA process, and this pre-evaluation discussion would not apply to such components. For the EP and IL commodities, some or all of the components are assigned equipment identifiers in the CCNPP equipment database. For these components, the Pre-Evaluation task includes an administrative step to remove these components from the scope of the AMR of the assigned system, and to bin these components for the commodity evaluation of the appropriate commodity group. These two cases are discussed below.

5.3.1 EPs

Electrical panels are assigned to a number of systems in the CCNPP equipment database because they are functionally related to the system components. In all cases, the passive intended function of such panels is to provide structural support to active system components contained in the panel and/or to ensure electrical continuity of power, control or instrumentation signals. Electrical panels include switchboards, motor control centers, control panels and instrumentation panels.

At this point in the Pre-Evaluation task, such panels are excluded from the AMR of their parent system and are instead administratively included with the EPs commodity evaluation. As will be described in Section 7 of this methodology, the commodity evaluation produces the same results as the AMR task described in Section 6 but the evaluation is adjusted to be more efficient for a particular component type.

5.3.2 ILs and Tubing

Many fluid systems contain a number of small ILs which are part of the systems' pressure-retaining boundary. Such small branch lines contribute to the passive intended function of maintaining the system PB and most are not subject to periodic replacement. Consequently, these ILs are subject to AMR. Instrument lines are subject to common environments, are made of common materials and perform the same passive intended function regardless of the system to which they are assigned. Therefore, the BGE IPA process identifies such ILs during the Pre-Evaluation task and excludes them from the AMR of the parent system. The commodity evaluation of ILs includes: 1) small bore piping, tubing and fittings from the root isolation valve to the instrument; 2) hand valves which are part of the instrument lines (such as equalization, instrument isolation and vent valves for pressure differential transmitters); and 3) any other components in the instrument line which contribute substantially to maintaining the pressure retaining function of the instrument line. Section 7.1.2 contains a discussion of how this third criterion for inclusion of components in the IL Commodity Evaluation is applied.

5.4 How the Pre-Evaluation Task Applies to Structures

For plant structures, a modified task is used to determine which SCs are subject to AMR.

5.4.1 Passive Versus Active

Section 4 of the IPA Methodology describes the seven intended structural functions which may cause a structure to be included within the scope of LR per §54.4 of the LR Rule. From reviewing these functions and the description of passive functions in Section 5.1.1, it is clear that all of the intended structural functions are passive. Therefore, the steps of the Pre-Evaluation task to characterize functions as active or passive are not needed for structures.

5.4.2 Short-Lived Versus Long-Lived

Plant structural components are not normally subject to periodic replacement programs. Therefore, structural components are considered to be long-lived unless specific justification is provided to the contrary. Such justification would be included in the LRA.

5.4.3 Structures Which are Also Designated as Systems

In two instances, plant structures are also characterized as systems in the CCNPP site documentation system and system-type components are associated with these "systems." For example, the primary containment structure is also designated as the containment system. All penetration seals, as well as several position switches and access doors, are listed as individual components of the containment system with unique equipment identifiers.

As discussed in Section 4, the techniques for scoping of a structure as well as those for scoping a system are applied to such a structure. Two distinct sets of scoping results are produced — one for the system components and one for the structural components. In this case, the Pre-Evaluation task described in the previous steps of Section 5 would be applied to the system scoping results. For the structural scoping results, Pre-Evaluation steps would not be performed for the reasons described in Sections 5.4.1 and 5.4.2.

5.5 Pre-Evaluation Results and Documentation

The Pre-Evaluation task produces results which serve as input to the AMR task and to specific commodity evaluations. These results and the documentation of the results are discussed below.

5.5.1 Pre-Evaluation Results

Section 5 identifies the SCs which are subject to AMR. This list of SCs and their intended passive functions serve as the input to the AMR task described in Section 6. Section 5 also removes certain passive, long-lived SCs from the scope of their parent system AMR, and includes them instead in the commodity evaluation for a specific commodity type.

5.5.2 Pre-Evaluation Documentation

The Pre-Evaluation task produces a list of the SCs which are subject to AMR for inclusion in the LRA.

6.0 AMR

This Section of the IPA Methodology describes how the components which were determined in Section 5 to be subject to AMR are evaluated for the effects of age-related degradation. It also describes the approach used to identify and evaluate aging management alternatives to determine which adequately manage the effects of aging. Figure 6-1 is a flow chart which represents the AMR process.

The AMR task fulfills the requirements of 10 CFR 54.21(a)(3)of the LR Rule:

> *For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.*

The input to the AMR task is the list of SCs subject to AMR along with the intended, passive functions for those SCs. The results of this task demonstrate the following for each input SC or group of SCs:

- Management of the effects of aging is not required because these effects are not detrimental to the ability of the SC to perform its intended function consistent with the CLB;
- Existing programs or activities will adequately[6] manage the effects of aging; or
- New programs or activities or the modifications to existing programs or activities will need to be implemented to adequately manage the effects of aging.

6 See Section 2.1 for the definition of "adequately manage."

Like the Pre-Evaluation task, the AMR task is usually performed on a system-by-system and structure-by-structure basis. The task described in this Section applies to SCs of both systems and structures with very few exceptions. These exceptions are described in the steps where they occur.

The AMR can be performed in one of two general ways. In some circumstances, it is possible to demonstrate that existing plant programs adequately manage the effects of aging without an explicit evaluation of the aging mechanisms. This approach is described in Section 6.1. In other instances; however, it is most efficient to evaluate the effects of specific aging mechanisms on the intended functions. Section 6.2 describes this approach.

AMR Process

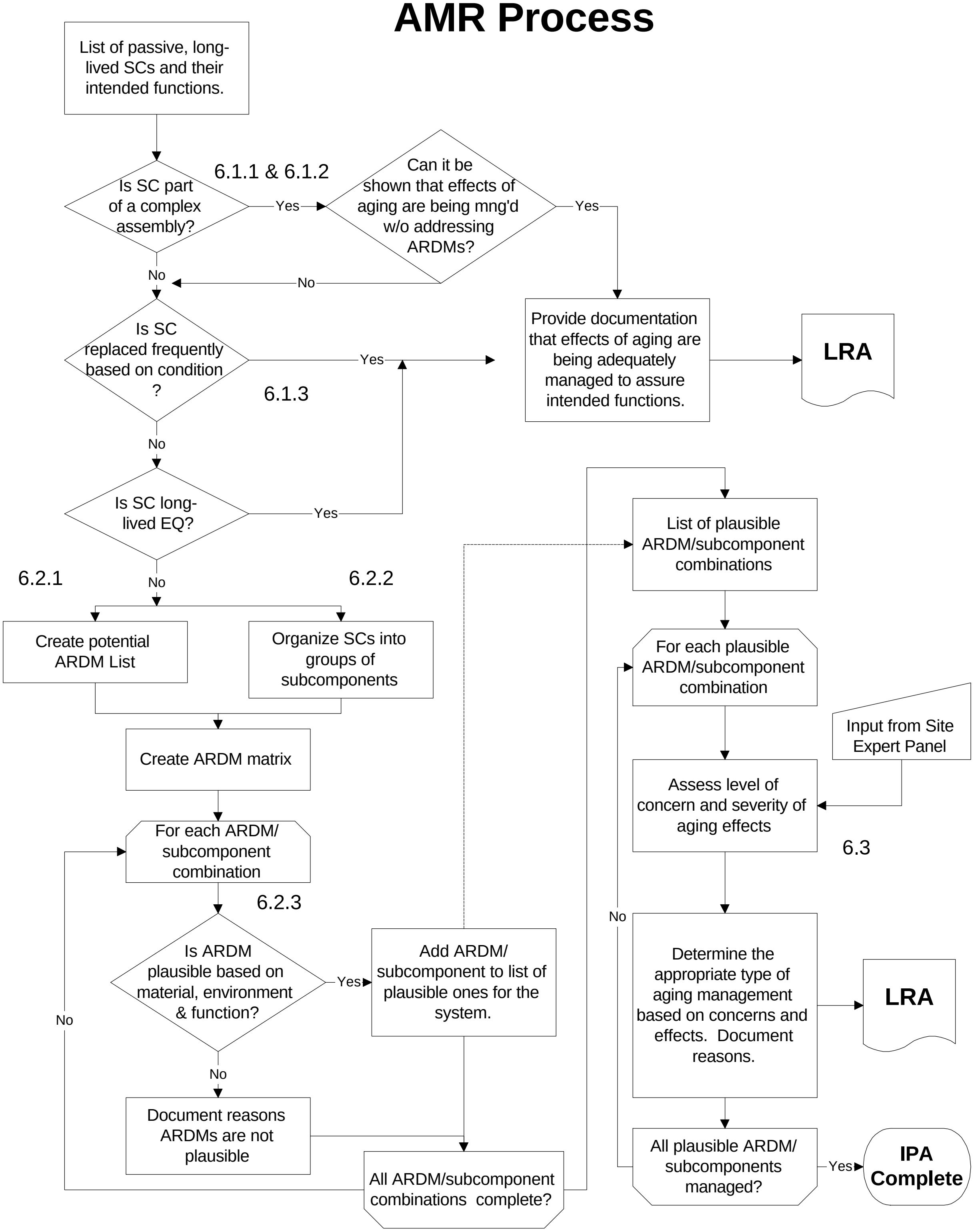

Figure 6-1

Where the approach described in Section 6.2 is followed, several alternatives for managing the aging effects may be viable and it is necessary to select from those alternatives. In addition, technological developments may produce additional viable alternatives in the future for either approach. Section 6.3 describes the CCNPP approach for evaluating and selecting aging management alternatives during the IPA process.

6.1 Justification that Effects of Aging are Being Managed Without Specifically Evaluating ARDMs

In several instances, a specific evaluation of the ARDMs is not required in order to justify that the effects of aging are being adequately managed by existing plant programs. These approaches are based on the Commission conclusion stated in the SOC accompanying the LR Rule.

> *As a plant ages, a variety of aging mechanisms are operative, including erosion, corrosion, wear, thermal and radiation embrittlement, microbiologically induced aging effects, creep, shrinkage, and possibly others yet to be identified or fully understood. However, the detrimental effects of aging mechanisms can be observed by detrimental changes in the performance characteristics or condition of systems, structures, and components if they are properly monitored. (60 FR 22474)*

Four cases are described in this Section. For three of these cases, the AMR demonstrates that the effects of aging on the passive function would be reflected in a change in one or more monitored performance or condition characteristics of the SCs. Therefore, by adequately monitoring these performance or condition characteristics, the effects of aging on the passive intended function are also adequately managed. In the other case, described in Section 6.1.3, the SCs are subject to a TLAA. The resolution of the TLAA will be provided by one of three methods described in Section 8.

6.1.1 Complex Assemblies Whose Only Passive Function is Closely Linked to Active Performance

For some complex assemblies of SCs, the principal intended function is an active function. Some of their components are subject to AMR because the components contribute to a passive pressure-retaining function to support the active functions of the entire assembly.

An example is the diesel generator supporting equipment. The pressure-retaining components of the diesel starting air, lube oil, fuel oil, cooling water and scavenging air system are subject to AMR because they contribute to a passive pressure-retaining function. However, there would be a readily observable affect on the diesel generator performance if the pressure-retaining components deteriorated significantly. For example, significant cooling water or lube oil piping leakage would result in increased bearing temperatures, and significant starting air leakage would affect diesel start times. Additionally, experience has shown that even minor leakage from any of these supporting subsystems is observed by operators conducting routine testing well before they result in actual performance degradation. These effects would be observed during routine testing, before the deterioration of the pressure-retaining components could affect the diesel's ability to perform its active intended function. Corrective actions to restore the passive function from its degraded condition are required by the performance testing program and by the normal site corrective action processes.

Because of the readily observable effects of passive function degradation on active performance, a sufficient method of managing the effects of all types of aging could be to subject the assembly of components to a rigorous performance and condition monitoring program. In the cited example, the diesel generator support systems are subject to surveillance requirements to demonstrate operability in accordance with the Technical Specifications and to a comprehensive reliability program required by other regulations. The conclusion of the AMR using this technique could be that continuing these types of performance and condition monitoring programs would ensure that the intended functions of the assembly will be adequately managed.

In some cases, the conclusion of the AMR using this approach may be that the discovery techniques available through the performance and condition monitoring programs are not timely enough to ensure intended functions as required by the CLB. For example, the discovery techniques used in a particular performance and condition monitoring program may only provide reasonable assurance that the intended function can be performed under normal loading conditions. Additional evaluation and/or inspection may be required to ensure the ability to perform intended functions under certain more severe loading conditions which are part of the CCNPP CLB. In this case, additional evaluations may be performed to demonstrate that the aging mechanisms which may affect the ability of SCs to perform under more severe loading conditions are not plausible for the SCs. Alternately, age-related degradation inspections, as described in Section 6.3.3.4, may be performed to determine whether there are aging effects of concern for the SCs being evaluated.

Because there may not generally be a close tie between degradation of passive SCs and the active performance of a train of equipment, the performance and condition monitoring AMR technique is used only in selected circumstances. The conditions listed below represent the circumstances where this approach should be followed rather than using one of the other AMR approaches. These conditions do not constitute a part of the AMR demonstration itself. The demonstration that these conditions are met would not be submitted as part of the LRA but would be maintained onsite.

- A complex assembly of components where the pressure-retaining function directly supports active performance of the assembly;
- The passive function is the pressure-retaining function and is not a fission product boundary function;
- The active intended functions are performed by redundant trains;
- Performance testing is well documented with verification that corrective actions assure the continued performance of all intended active functions; and
- The complex assembly is covered by the Maintenance Rule.

6.1.2 Component Assemblies Subject to Complete Refurbishment

For some complex assemblies of SCs, the entire assembly is subject to a program which requires complete refurbishment at periodic intervals. Components of such assemblies may be subject to AMR because their pressure-retaining function supports the active functions of the entire assembly. Deterioration of the pressure-retaining components would be discovered and corrected during the refurbishment activities before the deterioration could affect the intended function of the assembly in a manner not consistent with the CLB.

An example is the main steam isolation valve operator. This assembly contributes primarily to the active function of closing the main steam isolation valve in a specified amount of time. Because the valve operator uses a combination of hydraulic fluid pressure and compressed nitrogen to operate the valve, several components of this operator assembly provide a passive pressure-retaining function. The entire valve operator is removed from the system at regular intervals and refurbished. Some of the pressure-retaining components and subcomponents are replaced every refurbishment interval. Others are inspected and replaced if they meet certain described conditions. The entire assembly is re-assembled and tested to ensure satisfactory performance and then re-installed in the system. Such a refurbishment program manages all plausible aging effects to ensure that the intended function of the valve operator is maintained in accordance with the CLB. Therefore, this program may be credited as an adequate aging management program without considering specific aging mechanisms.

This approach is restricted to refurbishment programs that meet the following criteria:

- The refurbishment is conducted at regular intervals on a complex assembly of components where the pressure-retaining function only directly supports the active intended function of the assembly;
- The passive function is the pressure-retaining function and is not a fission product boundary function;
- The program requires complete removal of the component assembly from the system;
- The assembly components and subcomponents, including pressure boundaries, are inspected for signs of aging and other degraded conditions;
- The refurbishment directs replacement of components and subcomponents that are deteriorated excessively due to aging or other degradation; and
- The refurbishment includes post maintenance testing consistent with current industry practices and the CLB.

6.1.3 Long-Lived EQ Components

Components subject to EQ which have qualified lives less than 40 years are short-lived and would be excluded from the AMR during the Pre-Evaluation task. Components subject to EQ which have qualified lives of 40 years or greater are subject to a TLAA. The options for resolving TLAAs are described in Section 8. Completing one of these

TLAA options for long-lived EQ equipment will also serve to provide the required IPA demonstration.

Some portions of passive EQ SCs may not be covered by the EQ program. For example, the EQ program only qualifies the organic material of a solenoid valve. A separate AMR evaluation using the technique described in Section 6.2, will be performed to provide the required demonstration for those portions of passive EQ SCs which are not covered by the EQ program.

6.1.4 SCs Subject to Replacement on Condition

In the case of certain SCs, an indication of SC condition is used as the basis for replacement of a passive SC. For example, the copper-nickel tubes of a heat exchanger may have an intended pressure-retaining function. This function is passive since there are no moving parts or changes in configuration or properties involved in performing the function. Such tubes are not replaced based on a specific time period or qualified life so they would be included in the AMR. However, they are subject to eddy current testing which dictates when tubes must be plugged and a tube plugging limit which dictates when the tube bundle must be replaced. Plant experience shows that these heat exchangers are retubed every 10 to 15 years. In cases such as this one, where a plant parameter for a passive SC is linked to the ability of the SC to perform its intended function, and where plant operating experience has shown that the component is replaced frequently, the condition-based replacement program would be credited as the aging management program for the SCs.

Table 6-1 shows the criteria which are covered in the detailed demonstration for each SC or group of SCs subject to this AMR method. These detailed results are maintained onsite in an auditable format. The justification provided in the LRA to demonstrate that the effects of aging are adequately managed would include a summary of the detailed justification.

TABLE 6-1

CRITERIA FOR REPLACEMENT ON CONDITION PROGRAMS

Criterion 1 - Replacement programs based on condition or performance must ensure that the SCs identified as within the scope of LR will be replaced before degradation would result in loss of the SC intended function(s). For example --

- Is the discovery activity frequency interval less than the shortest time between failures of the SC intended function(s)?
- Based on the condition or performance trait monitored by this program, is the component replaced at intervals that are short relative to the life of the plant?
- Historically, have all maintenance preventable functional failures of SC intended functions been detected by the activity?

Criterion 2 - Replacement programs based on condition or performance must contain appropriate acceptance criteria which ensure timely replacement of the SCs.

- Does the activity have an action or alert value or condition parameter to determine the need for replacement of the SC?
- Does the action value or condition provide an appropriate means of assuring replacement of the component before the effects of aging would prevent any intended system functions?

Criterion 3 - Replacement programs based on condition or performance must be implemented by the facility operating procedures.

- Is the activity controlled by a site review process which includes controls over subsequent revisions?

6.2 Performing an AMR by Evaluating Aging Mechanisms

In some circumstances, the most efficient manner[7] to show that the effects of aging are being adequately managed is to evaluate the effects of specific aging mechanisms on the intended functions and to demonstrate that those effects are being managed. This Section describes this method of performing an AMR.

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[7] Unlike the methods described in Subsection 6.1, this method of performing the AMR could have been used for all SCs subject to AMR. However, this method is not always the most efficient method. For some SCs, even if one of the more efficient methods described in Subsection 6.1 would have been sufficient to demonstrate adequate aging management, BGE chose to use a more mechanistic approach due to other benefits derived from performing this approach.

6.2.1 Creating a Potential ARDM List

The first step of the specific evaluation of ARDMs is to determine which ARDMs must be evaluated. For system components, the list of such ARDMs is referred to as the "Potential ARDM List" for a given ET.

When an ET is encountered in an aging evaluation and the ET has not been evaluated as part of a previous evaluation, a new Potential ARDM List is created. Industry documents are reviewed to identify the aging mechanisms which need to be considered. From reference materials, a list of all of the ARDMs which might affect any SC of the given ET is compiled. The list also includes a discussion of the various stressors which cause or exacerbate the ARDMs. It also includes a list of any characteristics of selected SCs which might prevent the ARDMs. This Potential ARDM List is the list of ARDMs that will be considered for subsequent evaluations of SCs of this ET. The Potential ARDM List is updated as each SC of the same ET is evaluated.

The next step is to eliminate those ARDMs which are not applicable to any of the SCs in the system being evaluated. For example, creep is an ARDM which is included on the initial list for the ET for piping. However, when finalizing the Potential ARDM List for the Service Water System, this ARDM is eliminated as not applicable because the temperatures throughout the Service Water System are too low to warrant consideration of this mechanism. The basis for marking an ARDM as not potential is recorded on the Potential ARDM List for the system.

Structural components are not associated with a particular ET in the site equipment database, and therefore a modification to this step is needed for structural components. Instead of creating the Potential ARDM List for each ET, structural component types are divided into two categories: 1) concrete/architectural components; and 2) steel components; and a Potential ARDM List is created for each of these categories.

6.2.2 SC Grouping

If a system contains several SCs with similar characteristics, the evaluation can be made more efficient by grouping these SCs together for a common evaluation.

All components of systems are classified in the site equipment database with a particular DT code. Examples of such DTs are hand valves, check valves, pressure transmitters and heat exchangers. The DT can be further divided to facilitate the evaluation. For example, if the check valves of a particular system are made of two distinctly different materials, two separate groups may be formed. Other possible examples are listed below:

Internal Environment - All system piping which carries saltwater could be in one group while the instrument air piping which controls valves in the system would be in another.

External Environment - All system underground piping could be included in one group, while the above ground piping would be in another.

Design - Other design parameters besides material could be selected as grouping attributes. For example, plate and frame heat exchangers may be grouped separately from shell and tube heat exchangers.

The grouping attributes and the component IDs are recorded and each group is assigned a unique identifier.

Groups may be further subdivided into the individual subcomponents which make up the components in the group if this facilitates the subsequent evaluation. If certain subcomponents are not required for the SC to perform its intended, passive function, they are identified and excluded from further evaluation. For example, a group of air-operated valves may have an intended pressure-retaining function but may not have to reposition for any intended function. Therefore, the discs, seats and air operators of the valves in this group would not be subject to AMR because they do not contribute to an intended passive function. Whenever subcomponents are eliminated from further evaluation because they do not contribute to the intended, passive functions, the bases for these decisions are also documented.

Again, because of site documentation differences for structural components, the structural component type is used to establish the initial level of grouping in the same manner as DT is used for system components.

6.2.3 Create and Resolve the ARDM Matrix.

After completion of the system Potential ARDM List and after SCs are grouped and subdivided, an ARDM matrix is created and evaluated. The ARDM matrix consists of all potential ARDMs along one axis and all remaining subcomponents for a particular SC group along the other. Each ARDM/subcomponent intersection must be reviewed during this step.

For each ARDM/subcomponent combination, the following is considered: 1) the material of the subcomponents in the group; 2) the operating environment; and 3) the passive intended functions. If the ARDM does not affect the material, is not perpetuated by the environment or occurs to such a small degree that the intended function is maintained, the ARDM is designated as not plausible for the subcomponent. Although material, environment and function are mentioned separately above, when evaluating ARDM plausibility, all of the factors are considered together.

Integrated Plant Assessment documentation for this step consists of the list of the ARDMs that are plausible for each group of SCs subject to AMR and the rationale for designating each ARDM. This information is recorded in evaluation reports and maintained onsite. A list of the potential ARDMs that were evaluated for each group of SCs in the system is provided in the LRA.

6.3 Methods to Manage the Effects of Aging

This Section describes how the aging management methods are chosen and justified for the period of extended operations. Methods chosen for managing the effects of aging will be consistent with site strategies for maintenance of equipment material condition. One of the goals of aging management is to manage the effects of aging such that the intended functions are maintained consistent with the CLB. Consequently, each phase of the maintenance strategy discussed below takes this goal into consideration when determining the adequacy of an existing or proposed program or activity.

6.3.1 Phases of a Maintenance Strategy

An adequate maintenance strategy consists of four phases: Discovery, Assessment/ Analysis, Corrective Action, and Confirmation/Documentation

(1) **Discovery** - The first phase of a maintenance strategy is identification that detrimental effects of aging are or could be occurring. As stated in the SOC for the LR Rule:

> *The Commission believes that, regardless of the specific aging mechanisms, only age-related degradation that leads to degraded performance or condition (i.e. detrimental effects) during the period of extended operation is of principal concern for license renewal. Because the detrimental effects of aging are manifested in degraded performance or condition, an appropriate license renewal review would ensure that licensee programs adequately monitor performance or condition in a manner that allows for timely identification and correction of degraded conditions. (60 FR 22469)*

Aging can be self-revealing or identified through specific diagnostic techniques. Current examples of discovery methods include visual observation of external conditions, eddy current examination for flaws, and ultrasonic testing for detecting wall thinning. As discussed in Section 6.1.1, these discovery methods may require augmentation for LR to ensure that the effects of aging are discovered in a timely manner such that there is reasonable assurance that the CLB will be maintained. Some plant programs may use specific detection techniques to detect and monitor aging while others rely on walkdowns by plant personnel to observe and document degraded conditions or performance. Monitoring and evaluating industry experience also serves as a discovery activity for currently unknown or theorized aging mechanisms since other plants may discover aging effects before CCNPP.

(2) **Assessment/Analysis** - Once performance or condition degradation is discovered, its progress must be compared to criteria or other guidance to determine the degree of the degradation and the need for specific and generic corrective and preventive action. These criteria and guidance will depend on the characteristics of the degradation and the effects on the intended function. For example, a safety or safety support system must be capable of performing its specific safety function for accident prevention and/or mitigation as described in the CLB. Likewise, a system providing a function for a regulated event must be capable of performing that function under the conditions described in the CLB evaluation of the regulated

event. The assessment/analysis phase incorporates such requirements in determining the need for and nature of corrective actions after abnormal or degraded conditions are discovered. One possible result of such assessment/analysis would be to repeat the discovery phase using an expanded sample size or using an augmented or improved technique for discovering and quantifying the extent of a particular aging effect.

(3) **Corrective Action** - With the degree of degradation known, specific corrective action can be taken to ensure that the equipment performance or condition is restored and the intended function is maintained. Site procedures currently exist which require root cause analysis and actions to prevent recurrence to be included with corrective actions when appropriate.

(4) **Confirmation/Documentation** - After the corrective action is performed, post-maintenance verification or testing confirms that maintenance was performed correctly and the equipment is capable of performing its intended function. The corrective action and testing are documented as part of plant records for future reference.

In combination, these four phases provide a complete maintenance strategy. Sections 6.3.2 and 6.3.3 describe how discovery activities are identified and selected. Section 6.3.4 describes how the latter 3 phases are implemented.

6.3.2 Site Expert Panel Input

The selection of the appropriate method for detecting aging effects is performed through an expert panel review of each plausible ARDM/subgroup combination. The review is conducted on a system or commodity basis and, typically, consists of following plant representatives:

- The system or commodity aging evaluation engineer;
- The cognizant system engineer;
- Appropriate plant program managers/technical area specialists; and
- The aging management implementation engineer.

Each member brings specific focus and talent to the expert panel.

The aging evaluation engineer presents the results of the system aging evaluations highlighting the intended functions of the systems, the components subject to AMR, and the plausible aging effects. The aging evaluation engineer also proposes the methods by which the effects of aging can be managed.

The system engineer brings his knowledge of the system and functional requirements, knowledge of the plant and industry experience with the system, and familiarity with system inspection, surveillance, testing and maintenance results. The system engineer also provides site technical concurrence to execute the aging management methods for his system under a renewed license.

Each plant program manager/technical area specialist brings his expertise in a specialized area (such as non-destructive examination, EQ, chemistry, materials, fatigue) and provides a perspective in determination of program applicability and feasibility. These individuals also provide technical concurrence that their program methods will effectively detect and monitor the specified aging effects and are presently the preferred methods.

The aging management implementation engineer facilitates the panel meetings, provides consistency between system and commodity technical discussions, ensures involvement of the appropriate plant personnel, and ensures closure of open items.

The panel as a team determines the appropriate methods to manage the effects of aging for the given system or commodity considering two main factors:

- The likelihood the ARDM will occur for the specific application; and
- How the effects of the mechanism progress.

If the panel determines that the ARDM occurs and progresses relatively rapidly, then prescriptive plant programs or system modifications may be warranted. Age-related degradation inspections and/or performance or condition monitoring may be warranted if:

- The mechanism has not been seen yet in operating plants;
- Present knowledge indicates progression is gradual; and
- The known characteristics of the ARDM indicate a potentially severe impact on the system intended function.

  Continuing to monitor and evaluate industry experience may be appropriate if:

- There is little or no experience with a particular mechanism occurring for the system environment;
- Current knowledge indicates the ARDM progresses relatively slowly; and
- The potential consequences to the system intended function are not significant.

6.3.3 Selection of Aging Management Alternatives for Discovery

Once degradation is discovered, the step described in Section 6.3.4 will ensure that the appropriate Assessment/Analysis, Corrective Action, and Confirmation/Documentation occur for all SCs. Therefore, for the purposes of the IPA, it is only necessary to establish how the degradation will be discovered on a system-by-system basis.

Appropriate methods for discovering the effects of aging are selected for all of the SCs subject to the AMR based on the expert panel approach. Each of the methods can be categorized into one of the following groups.

6.3.3.1 Plant Programs

Plant programs are often the most direct and systematic method of detecting and mitigating the effects of aging. They already exist to meet regulatory requirements or recommendations, warranty requirements, or to preserve economic investment based onsite experience. They are typically selected as the method of discovering aging when they exist and can discover the effects of the plausible mechanism.

The plant programs applicable to the system are identified and reviewed to determine if they may serve to discover aging effects for the long lived passive components. In some cases, existing condition monitoring or functional testing may be sufficient; existing focused inspections may be sufficient in others. Programs adequate to detect or monitor the effects of aging during the period of extended operations are credited without modification.

Whenever an activity required by an existing industry code such as ASME Section XI is credited as an aging management program, the specific version of the code to which BGE is currently committed should be noted in the AMR report and LRA documentation.

Existing plant programs can also be modified to ensure the discovery phase of the maintenance strategy is adequate for the period of extended operation. Examples of modifications to an existing program include, but are not limited to, the following:

- Adding components to inspection procedures for specific aging effects;
- Adding specific aging effects mitigation procedures; and
- Tailoring of record keeping and trending requirements.

If no existing plant program can be adapted to address the aging effects for the given group of SCs, new programs may need to be implemented.

Some modifications to existing programs and new programs may be implemented prior to submittal or approval of the LRA. Alternately, the LRA may include a commitment to implement the program or modification at an appropriate future date before or, with appropriate justification, during the period of extended operation.

Examples of existing plant programs are shown in Table 6-1.

TABLE 6-1

Examples of Existing Plant Programs	
Maintenance (Preventive)	Materials Testing and Evaluation
Maintenance (Corrective)	Motor-Operated Valve Program
Maintenance Standards Program	Performance Evaluation Program
Check Valve Reliability	Performance Evaluation Program (Operations)
Eddy Current Testing	Plant Lay-up and Equipment Preservation
Electronic Cable Degradation	Post-Maintenance Testing
Engineering Test Procedures	Pressure Test Procedures
Surveillance Test Procedures	Plant Tours
Fatigue Monitoring	Protective Coating and Painting
Functional Testing	System Walkdowns
Environmental Qualification	Thermography
Inservice Inspection	Vibration Monitoring
Loose Parts Monitoring	Thermal Performance Monitoring
Lube Oil Analysis	Operator Rounds

6.3.3.2 Site Issue Reporting (IR) and Corrective Action Program

In cases where the effects of aging are observed in less formal activities or as a result of work in the vicinity, the IR and corrective action program is relied on for discovery. Examples of less formal activities are:

- Plant tours by supervisors and managers;
- Management and supervisory job observations;
- Maintenance planning walkdowns;
- Walkdowns of planned and completed modifications;
- Fire watches; and
- Personnel safety equipment inspections.

Any observed or suspected condition that requires significant corrective action, whether related to the purpose of a specific activity being performed or not, is documented via an IR. These methods for discovery are normally complementary to other, more formal activities, such as age-related degradation inspections. If such activities are relied on as the principal means of discovery, appropriate justification would be provided in the LRA.

6.3.3.3 Plant Modifications

Plant modifications may be appropriate where:

- Plant programs cannot effectively discover the effects of aging;
- Experience indicates that the mechanism is occurring; and
- The progression is relatively rapid.

Modifications will occur as part of the normal site modification process which currently exists for improving and updating plant response, performance and reliability.

Examples of modifications which might result from the aging evaluations include, but are not limited to, the following:

- Relocation of equipment to a less aggressive environment;
- Change of material to improve resistance to the aging mechanism; and
- Change in the equipment operation.

Modifications to plant equipment may be implemented prior to submittal of the LRA. Alternately, the LRA may commit to implement a modification at an appropriate future date. With justification, this date may be during the period of extended operations.

6.3.3.4 Age-Related Degradation Inspections

Two distinct cases of age-related degradation inspections are discussed below. Others may also be possible.

Case 1: Inspection to Support a Non-Plausible Determination

In some cases aging mechanisms are possible but the effects of the aging are expected to have minimal consequences due to the equipment material and operating conditions. For example:

- A structure may have been built with a concrete mix that provides maximum resistance to freeze-thaw.
- A tank may have been built of stainless steel using strict welding controls to minimize the chance of stress corrosion cracking.

In this case, an inspection could be conducted to provide additional assurance that significant degradation is not occurring or that the rate is sufficiently slow to preclude concern during the period of extended operation. Alternatively, the inspection might conclude that additional inspections are needed during the period of extended operation.

The scope of such inspections would typically be a representative sample of the population. Where practicable and prudent, the sample would be biased to focus on bounding or leading components. For example:

- The portion of a structure more likely to experience the ARDM; or
- A statistically representative sample of the valves made of a particular material;

If the inspection indicates little or no degradation, the conclusion could be reached that the degradation will not result in loss of component function during the period of extended operation, and therefore, no additional aging management activities or programs would be required. Significant degradation, on the other hand, would trigger action under the existing corrective action program and the need for additional inspections would be evaluated.

Where the inspection demonstrates that there is no significant degradation and no program is needed to manage the effects of aging, resolution of the aging mechanism would be documented by describing:

- The inspection process and results; and
- Why it is an adequate approach to disposition the ARDM for the SC group.

Case 2: Inspection to Validate an ARDM Mitigation Program

In other cases, programs may be in place which prevent or mitigate the effects of aging. These aging effects could, if left unmanaged, degrade the capability of SCs to perform their passive intended functions. In these cases, relying upon the mitigation program may not provide the necessary level of assurance that the passive intended function will be maintained during the period of extended operation. For example:

- An underground piping system may be wrapped with a protective material to prevent contact with moisture and may also be subject to an impressed current cathodic protection system designed to prevent corrosion. However, because the piping is buried and the consequences of failure would be significant, a decision might be made to perform an inspection of a representative sample of the piping exterior to confirm that the mitigation measures have been effective in controlling aging.
- A fluid system may be subject to chemistry controls which minimize impurities and maintain a basic pH to limit corrosion of carbon steel components. However, because of the large amount of piping and other components subject to such treatment throughout the plant and the range of environmental factors, an inspection of a representative sample of components could be conducted to confirm that the chemistry controls in place have been effective in controlling the effects of aging.

In these cases, inspections could be conducted to confirm that the mitigation programs are effective in preventing or mitigating the aging effects which they were designed to control.

Again, the scope of such inspections would typically be a representative sample of the population of components of concern. Where practicable and prudent, the sample would be biased to focus on bounding or leading components. For example:

- The underground piping system which is closest to the water table and therefore, most likely to have been subjected to moisture; and
- The piping system which has experienced the worst history of chemistry transients and/or has the most susceptible locations.

If these inspections reveal little or no degradation, the conclusion could be reached that the mitigation programs are sufficient to manage the effects of aging during the period of extended operations. Significant degradation, on the other hand, would trigger action under the existing corrective action program and the need for additional inspections would be evaluated.

Where the inspection demonstrates there is no significant degradation and the existing program is adequate to manage the effects of aging, this would be documented by describing:

- The attributes of the program which prevents or mitigates the aging effect; and
- The inspection process and results.

For both of the cases described above, the inspection technique would need to be capable of detecting the effects of aging identified by the AMR. Acceptance criteria for these inspections would be consistent with current practices which account for the SC's ability to perform intended functions in accordance with the CLB.

For both cases, the inspections described above may be completed before submittal of the LRA. When such an early inspection detects no signs of significant aging as expected, there is no need to extrapolate the results of the inspection. If, on the other hand, the inspection reveals significant degradation or unexpected conditions, the results would either be conservatively extrapolated through the end of the period of extended operation or future inspections would be conducted to track the progress of the unexpected degradation. The frequency of such future inspections would be commensurate with the safety significance of the SCs being inspected, as well as consistent with the results discovered during the initial inspection.

Alternately, the LRA may commit to conduct the inspection prior to the period of extended operation or, with justification, during the period of extended operation. If industry experience resolves the aging issue in the interim, the commitment to perform the inspection could be cancelled using existing site commitment management procedures.

6.3.3.5 Industry Operating Experience

Monitoring plant and industry experience provides the principal discovery means for unknown and theorized aging mechanisms. Additionally, monitoring industry experience may be included as one feature of a multi-feature aging management approach when appropriate.

The materials used at CCNPP are common to nuclear plants and to many non-nuclear power plants that have long operating histories. Monitoring plant and industry experience therefore provides timely information related to unknown and theorized ARDMs, so that there is reasonable assurance that such ARDMs would be discovered before they severely affect intended functions at CCNPP. It also provides assurance that appropriate changes are made to existing programs.

Industry information is distributed across the nuclear industry via Institute of Nuclear Power Operation's Significant Event Evaluation Information Network program, which is a small part of Industry's response to NUREG-0737. The plant program for industry experience reviews problems and events across the industry and evaluates the significance and applicability to CCNPP.

Examples of information that the program captures are:

- Part 21 Notices;
- NRC Bulletins;
- NRC Information Notices;
- NRC Generic Letters;
- Vendor Information Letters;
- Operating Experience Information;
- Significant Event Reports;
- Operations and Maintenance Reminders; and
- Significant Operating Experience Reports.

In some cases, the aging evaluation may be based on information from the nuclear power industry or other industries that indicates unexpected deterioration may occur. Although the aging effects may not have been detected at CCNPP or most other plants with similar equipment, similarities in materials and environments may make it possible for the aging effects to occur at Calvert Cliffs. In these cases, discovery has already occurred through notification from NRC, Nuclear Energy Institute, Institute of Nuclear Power Operations, Owners Groups, or vendors.

The site issue reporting and corrective action process requires review and evaluation of the industry experience, and comparison to conditions at CCNPP to determine if additional action is needed here. If resolution of the issue is in progress, it will not necessarily be completed prior to LRA submittal or approval. The site issue reporting and corrective action process ensures that assessment/analysis occurs and appropriate action is taken.

For example, a current industry issue is PWSCC of Alloy 600. Baltimore Gas and Electric Company has been closely involved in the industry and owner's group efforts to resolve Alloy 600 issues. Baltimore Gas and Electric Company has established a multi-disciplined internal working group to evaluate implications of Alloy 600 aging for CCNPP. The working group used current industry knowledge and material and environmental properties to determine the susceptibility of Alloy 600 PB components to PWSCC. For some components where PWSCC was determined to be more likely, more proactive steps have been taken or are being considered, such as replacement, nickel plating or destructive testing. For reactor vessel head penetrations at CCNPP, the Alloy 600 working group determined that PWSCC will initiate and propagate much slower than at many other plants. Inspection results from other plants continue to be reviewed by BGE and continue to suggest no immediate concern for CCNPP. Additional plants are planning inspections. At this time, BGE cannot conclude that inspections will be needed at CCNPP. However, the processes are in place to ensure appropriate future decisions are made based on accumulated industry knowledge.

6.3.4 Implementing the Assessment/Analysis, Corrective Action and Confirmation/ Documentation Phases of the Maintenance Strategy

The last three phases of the maintenance strategy are required by the CLB and are provided by the site IR and corrective action process. Any observed or suspected condition that requires significant corrective action, whether related to the purpose of the specific activity being performed or not, is documented via an IR. Initiation of an IR causes the degraded condition or performance to be evaluated for immediate personnel or nuclear safety concerns, operability concerns, and reportability. The IR is screened and classified to ensure that timely corrective action is taken.

Actions necessary to resolve the IR are assigned to the responsible organization. The IR remains open until appropriate actions have been completed and documented. For significant events and issues, an event investigation and root cause analysis is conducted to aid in preventing reoccurrence.

Therefore there is reasonable assurance that timely discovery of aging issues and effects will result in appropriate action to evaluate, correct, document, and report them.

6.3.5 Aging Management for Aging Issues Associated with a Generic Safety Issue (GSI) or Unresolved Safety Issue

If there is an outstanding generic issue (GSI or Unresolved Safety Issue) associated with an identified aging effect or aging management practice, the SOC to the Rule (60 FR 22484) provides three options: 1) If the issue is resolved before LRA submittal, the applicant can incorporate the resolution into the LRA. 2) An applicant can justify that the CLB will be maintained until a point in time when one or more reasonable options would be available to adequately manage the effects of aging. (For this alternative, the applicant would have to describe how the CLB would be maintained until the chosen point in time and generally describe the options available in the future.) 3) An applicant could develop a plant-specific program that incorporates a resolution to the aging issue.

In determining the appropriate aging management practice for SCs affected by GSIs and Unresolved Safety Issues, these options should be considered throughout the steps of Section 6.3 and one of the options chosen as appropriate.

For example, the effects of a particular aging mechanism on a specific material may be designated by the NRC as a GSI. Baltimore Gas and Electric Company may choose option 2) above to address this issue in the IPA. Analysis could be used to demonstrate that other plants are more susceptible to the particular aging effects than CCNPP. Based on this analysis, reliance on continued participation in owner's group activities or other industry activities, including review of inspection results from the more limiting plants, could be used to demonstrate that the SC intended functions will be maintained consistent with the CLB. Alternate actions could also be developed as contingencies, depending on the results discovered at the limiting plants. In this manner, the aging issue associated with the GSI could be managed for the purposes of the IPA. Ultimately, resolution of the GSI would include actions, if necessary, which would be implemented under the CLB.

6.4 Plant Program Documentation

Documentation in the LRA for this task consists of a demonstration that the effects of aging are adequately managed as well as a description of the programs and activities which were identified during the AMR and are relied upon to manage the effects of aging. Program modifications or new programs which need to be implemented in order to adequately manage the effects of aging for the period of extended operation would be described briefly. A summary description of these existing programs and activities, program modifications and new programs are included in the FSAR Supplement. Detailed justification of the adequacy of the programs will be maintained onsite to serve as the basis for the demonstration provided in the LRA and the summary description provided in the FSAR Supplement.

6.5 IPA Summary

The completion of the AMR task concludes the IPA required by the LR Rule. The IPA process demonstrates that the effects of aging have been identified and are being or will be adequately managed. The next section of this methodology describes several specific cases where a slightly different process is used to provide the demonstration required for the IPA.

7.0 COMMODITY APPROACHES TO AMR

As discussed briefly in Section 1 and 4 of this methodology, the approach described in the first six sections of the methodology was followed for all plant SSCs with only a few exceptions. These six exceptions are described in this section.

The intent of a commodity evaluation is identical to the normal IPA approach; i.e., to demonstrate that the effects of aging are adequately managed. For each case discussed in this section, increased efficiency was the primary motivation in adopting an alternate approach.

For the purposes of discussion, the six commodity evaluations are divided into two groups: 1) those that replace only the AMR task of the IPA (Section 7.1); and 2) those that replace the entire IPA process (Section 7.2). Table 7-1 shows the six commodity evaluations and which belong to each of the categories described above.

TABLE 7-1

Commodity Evaluation	Equivalent to Entire IPA or Just AMR?
EPs	AMR
ILs	AMR
Cables	IPA
Cranes and Fuel Handling Equipment	IPA
Component Supports	IPA
FP Equipment	IPA

7.1 Commodity Evaluations Which Cover Only the AMR Task

For the EPs evaluation and the ILs evaluation, the tasks of system level scoping, component level scoping and pre-evaluation are performed as described in Sections 3, 4 and 5, respectively. The output of these tasks for the many systems which contain one of these two commodities is a list of the SCs subject to AMR. The performance of the AMR is split into the system AMR and commodity AMRs. The system AMR is conducted as described in Section 6. The commodity AMRs are conducted as described below.

7.1.1 EP Commodity Evaluation

For many fluid systems, the list of SCs subject to AMR includes many pressure-retaining fluid system components and a relatively few EPs which provide structural support to active electrical equipment. All of these components could have been evaluated as part of the system AMR. However, the expertise of the evaluator and the type of reference materials and plant documentation needed to perform the AMR for these two types of equipment is substantially different. Furthermore, the AMR of the EPs requires a level of expertise, reference material and plant documentation similar to that needed for other SCs in electrical distribution and instrumentation systems. Therefore, for efficiency reasons, the EPs are removed from the scope of each system AMR and all EPs (electrical distribution, instrumentation and panels supporting mechanical system operation) are grouped into a common commodity evaluation.

The first step of the EP commodity evaluation is to review the scope of all of the pre-evaluation results and to include all EPs subject to AMR in the commodity evaluation, regardless of the system the panel is assigned to in the site equipment technical database. Performing this step maintains the link between the scoping and pre-evaluation results, which are done system-by-system, and the scope of the commodity evaluation. For some systems, the only components in the system which were subject to AMR were those included in the scope of the EP commodity evaluation. For these systems, no system AMR was performed at all since the EP commodity evaluation addressed all system components requiring an AMR.

After the scope of the commodity evaluation is established, the IPA process for conducting an AMR described in Section 6.2 is applied to the newly formed scope of EPs in exactly the same manner as it is applied to a plant system. Panels are grouped by common material, function and environment. Potential ARDMs are listed. Age-related degradation mechanisms matrices are created and resolved, and aging management alternatives are evaluated.

7.1.2 IL Commodity Evaluation

For many fluid systems, the list of SCs subject to AMR includes many pressure-retaining components which are part of small branch ILs. Regardless of which system these ILs are part of, certain common characteristics are shared with respect to aging management.

- All consist of piping and/or tubing which contribute to only one passive intended function, i.e., the pressure-retaining boundary of the system;

- All include instrumentation which would be affected to some extent by significant PB leakage; and
- All system piping to which these ILs are attached is also subject to AMR.

Because of these common characteristics, the BGE IPA process includes an IL commodity.

Again, the scoping and Pre-Evaluation tasks of the IPA are performed using the IPA approach described in Sections 3 - 5. During the Pre-Evaluation task, the IL components are separated from the remainder of the system pressure-retaining boundary and are targeted for a commodity evaluation. Similar to the EP commodity evaluation, the first step of the IL commodity evaluation specifies the scope of the evaluation. For every fluid system subject to AMR, pre-evaluation results are reviewed. Tubing, fittings, hand valves and any other in-line components which are associated with the instrument and contribute substantially to the pressure-retaining function are included in the scope of this commodity evaluation. A determination has been made in 10 CFR 54.21(a)(1) that certain component types should be excluded from the AMR. Those specifically listed in 10 CFR Part 54 (as being excluded from the AMR) include pressure transmitters, pressure indicators and water level transmitters. Based on this guidance in the LR Rule, the contribution of these components to the passive, pressure-retaining function is determined not to be substantial enough to warrant an AMR, and these components are not included in the IL commodity evaluation. Other components with the same characteristics as those listed in §54.21(a)(1), but not specifically listed in this section of the Rule (e.g., differential pressure transmitters and indicators, pressure switches, water level indicators), are also determined not to be subject to AMR for the same reason. A correlation to the generic exclusion from the AMR for these additional component types will be provided in the IL Commodity Evaluation LRA Section. This correlation will consist of a discussion of how these component types have the same characteristics as those listed and excluded from the AMR in §54.21(a)(1) of the LR Rule.

At this point, one or more of the AMR methods described in Section 6.1 and 6.2 are performed on ILs in the scope of this evaluation. Appropriate aging management alternatives are then selected using the techniques described in Section 6.3.

7.2 Commodity Evaluations Which Cover All Scoping and IPA Tasks

For cables, structural supports, FP equipment and cranes/fuel handling equipment, the commodity evaluation, the process described in this section covers the component level scoping, the pre-evaluation and the AMR tasks.

7.2.1 Cables Commodity Evaluation

The CCNPP equipment database does not contain specific equipment connectivity for individual cables. Instead, a separate Circuit and Raceway database contains information on cables, their service function (power, control or instrumentation), their materials and their from and to locations. Correlation of cable schemes to individual raceways, equipment and rooms is then possible using the information in this Circuit and Raceway database and design drawings. Because of these differences in site documentation techniques, the BGE IPA process does not include cables within any of the system AMRs, but instead evaluates cables as a separate commodity.

7.2.1.1 AMR for Cables Subject to the EQ Program

The cable commodity evaluation tasks starts with all site cables, regardless of whether they support any of the intended functions described in §54.4. As discussed in Section 6.1.4, SCs subject to the EQ program are associated with a TLAA that will be evaluated as described in Section 8. Therefore, no further review of EQ cables is performed during the cables commodity evaluation.

7.2.1.2 AMR for Non-EQ Cables

For the remaining cables, the potential ARDMs which could affect CCNPP cables are considered as discussed in Section 6.2.1. Cables are grouped by common material characteristics as described in Section 6.2.2 and the potential ARDM(s) are evaluated to determine which are plausible for the groups of cables as described in Section 6.2.3. At this point, the component level scoping task is performed, applying the principles described in Section 4, to determine which of the cables which are subject to plausible ARDMs are within the scope of LR. The Pre-Evaluation task is not performed during this commodity evaluation since all cables are passive and long-lived.

For those cables subject to plausible ARDMs which are within the scope of LR, aging management alternatives are selected using the steps described in Section 6.3

Therefore, the result of the commodity evaluation is the justification that for all cables within the scope of LR, the effects of aging will be adequately managed by plant programs or activities, or the effects will not prevent the intended functions of the cables during the period of extended operations.

7.2.2 Cranes/Fuel Handling Equipment Commodity Evaluation

The system level scoping results identify five systems within the scope of LR which are related to cranes and fuel handling. Because the only intended function of these five systems are structural in nature, these five systems are included in a commodity evaluation instead of being addressed individually in the standard IPA process. The five systems are listed below:

- Spent Fuel Storage
- Refueling Pool
- New Fuel Storage and Elevator
- Fuel Handling
- Cranes

The first step of this commodity evaluation is to determine which components in these systems contribute to the intended functions. The UFSAR and Q-List documentation is consulted as described in Section 4.2 to determine which components of these systems contribute to the intended structural functions and are therefore within the scope of LR.

Once the components within the scope of LR are defined, the next step is to determine which of these components have already been addressed for their intended, structural type function as part of another AMR (e.g. the AMR of the building which houses the component[8] or the commodity evaluation of structural supports). Any such components are eliminated from the scope of this commodity review. For example, the refueling pool structural concrete, stainless steel liner and the fuel transfer tube are addressed in the AMR of the containment. The spent fuel racks and the spent fuel pool structural concrete and liner are already addressed in the AMR of the Auxiliary Building. These components are therefore eliminated from the scope of the crane and fuel handling commodity evaluation.

The next step of the commodity evaluation is to determine which portions of the cranes/fuel handling equipment listed above are subject to AMR. This is accomplished by reviewing the equipment using a process similar to Section 5 Pre-evaluation and determining those components which contribute to the intended functions through moving parts or a change in configuration or properties. These components are active and, therefore, are eliminated from the AMR[9].

The remaining passive components are evaluated for the effects of aging using the techniques described in Section 6.2. Potential ARDM lists are documented for the structural component types. The effects of the potential ARDMs are evaluated to determine if they could prevent the performance of the intended function. The periodic inspections and testing programs for designated heavy load handling equipment, as well as other plant programs and activities, are reviewed to determine whether they adequately manage the effects of the plausible ARDMs. The steps described in Section 6.3 are used to determine the appropriate aging management alternatives and these decisions are documented.

7.2.3 Component Supports Commodity Evaluation

Component supports are associated with equipment in almost every plant system. They perform the same basic function, regardless of the system with which they are associated. For this reason, it was determined that a commodity evaluation of component supports would be more efficient to address these supports than evaluating them as part of the system AMR.

This commodity evaluation begins by performing a scoping task similar to the component level scoping of structures described in Sections 4.2.3 and 4.2.4. A generic list of component support types is developed by reviewing industry and plant-specific information, including Seismic Qualification Utility Group guidance. American Society of

8 Because the scoping process for structures addresses all structural support functions for equipment housed by the structure, it is expected that the majority of these components would have already been addressed; however, this step of the commodity evaluation is intended to confirm the process.

9 It is conservatively assumed that no components or subcomponents are replaced based on time or qualified life.

Mechanical Engineers Section XI Component support inspection documentation and the CCNPP System Level Scoping Results. All component support types which might provide support for components within the scope of LR are determined. The results of this step is a listing of the components support types subject to AMR for each system within the scope of LR.

Except for the exclusion of snubbers, the remaining component supports are treated as passive, long-lived structural components and are subjected to the AMR. No other pre-evaluation type step is performed for this commodity evaluation.

The AMR of component supports is then conducted using steps similar to those described in Section 6.2. Potential ARDMs are identified per Step 6.2.1, and the ARDM matrix is resolved as described in Section 6.2.3. (The intent of component grouping, as described in Section 6.2.2, is already accomplished by the selection of component support types during the scoping steps.) Once the plausible aging mechanisms are determined for each component support type, the steps of Section 6.3 are performed to choose appropriate aging management alternatives for adequately managing the effects of aging for these reports.

7.2.4 FP Equipment Commodity Evaluation

Over half of the systems which are included in the scope of LR contribute to one or more FP functions. These functions include both fire suppression/detection functions and functions related to equipment used to demonstrate alternate safe shutdown paths in the event of a severe fire (10 CFR Part 50 Appendix R). For the vast majority of these systems, the normal component level scoping task described in Section 4 of this methodology is performed. However, there are seven systems which are in scope for LR primarily because of FP functions[10]. For these systems, the alternate scoping steps described in Section 7.2.4.1 are used.

Some passive intended FP functions are performed by fluid systems which are not SR. For the SCs which are subject to AMR only because of such passive intended functions, an alternate AMR technique is described in Section 7.2.4.2.

7.2.4.1 Scoping of Systems with Primarily[11] FP Intended Functions

The seven systems, which are in scope for LR primarily because of FP functions, are listed below.

- Well and Pre-Treated Water
- FP
- Plant Heating

[10] i.e., The only intended functions of three of the seven systems is a FP function. The other four systems have a FP function and a containment isolation function.

[11] See previous footnote.

- Condensate
- Plant Drains
- Liquid Waste
- Fire and Smoke Detection

Due to similarity of function, and the fact that most of the FP intended functions are active, an alternate approach is used for conducting the component level scoping of these systems. For these seven systems, identification of detailed system functions is performed as described in Section 4.1.1 of this methodology. However, after performance of this step, the intended functions are reviewed using the pre-evaluation step described in Section 5.1 to determine if the functions should be categorized as active or passive. The subsequent steps of the component level scoping task (review of MEL, development of function catalogs and generation of scoping results table) are then conducted on only the passive intended functions of the system and the remainder of the pre-evaluation (short-lived versus long-lived) is completed on only these scoping results.

The avoided steps in this modified task are the creation and further consideration of function catalogs for the active functions. Had the active function catalogs been created during the component level scoping task, the components in these function catalogs would have been excluded from the AMR in Section 5.1 because they contribute to only active functions. Therefore, this steps produces the same list of SCs subject to AMR as would have been produced by the process described in Sections 4.1 and 5.

For all of the remaining systems and structures with FP functions, the component level scoping is performed as described previously in Section 4.

7.2.4.2 AMR of FP Pressure-Retaining Components

The pressure-retaining SCs of fluid systems, which are in the scope of LR only because of their contribution to a FP intended function, are addressed in this Section.

The SOC accompanying the LR rule justifies exclusion of SCs associated with active fire suppression/detection functions from the scope of AMR based on the plant's FP Program.

> *The FPP* [Fire Protection Program] *is part of the CLB and contains maintenance and testing criteria that provide reasonable assurance that fire protection systems, structures and components are capable of performing their intended function. The Commission concludes that it is appropriate to allow license renewal applicants to take credit for the FPP as an existing program that manages the detrimental effects of aging. The Commission concludes that installed fire protection components that perform active functions can be generically excluded from an aging management review on the basis of performance or condition-monitoring programs afforded by the FPP that are capable of detecting and subsequently mitigating the detrimental effects of aging. (60 FR 22472)*

Although the SOC specifically refers only to SCs which contribute to active functions, the justification could apply equally to "installed FP components that perform *passive* functions." Therefore, for the fire suppression/detection systems, the AMR applies the principles of Section 6.1.1 and consists of demonstrating that the performance and condition monitoring programs required by the CCNPP FP Program address the pressure-retaining portions of these fluid system so that the effects of aging are adequately managed.

For the pressure-retaining components in fluid systems credited as alternate safe shutdown equipment for Appendix R, the AMR is performed in accordance with Section 6.2 of this methodology.

7.3 Commodity Evaluation Results And Documentation

Integrated Plant Assessment documentation for commodity evaluations consists of a demonstration that the effects of aging are adequately managed for the commodity groups being evaluated and a description of the programs identified during the evaluation which are relied upon to manage the effects of aging. Program modifications or new programs which need to be implemented in order to adequately manage the effects of aging for the period of extended operation would be described. A summary description of the existing programs and activities, program modifications and new programs would also be included in the FSAR Supplement.

8.0 TLAA REVIEW

This section of the IPA methodology describes the task for reviewing analyses which may only be valid during the original 40-year license. This task is performed for the entire plant, whereas the Pre-evaluation and AMR tasks are performed for each system and structure in the scope of LR.

In 10 CFR 54.3, TLAAs are defined as:

> *Time-limited aging analyses, for the purposes of this part, are those licensee calculations and analyses that:*
>
> *(1) Involve systems, structures, and components within the scope of license renewal, as delineated in §54.4(a);*
>
> *(2) Consider the effects of aging;*
>
> *(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;*
>
> *(4) Were determined to be relevant by the licensee in making a safety determination;*
>
> *(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in §54.4(b); and*
>
> *(6) Are contained or incorporated by reference in the CLB.*

The SOC accompanying the LR Rule clarifies the definition of TLAA by explaining that an analysis is relevant if it "provides the basis for the licensee's safety determination and, in the absence of the analysis, the licensee may have reached a different safety conclusion." (60 FR 22480) The LR Rule requires that a list of TLAAs (as defined above) be provided in the LRA, as well as a demonstration that one of the following is true for each TLAA:

(i) The analyses remain valid for the period of extended operation;

(ii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The TLAA Review task produces the required list of the TLAAs which are subject to LR review, and demonstrates that these analyses will meet one of the three conditions listed above. Figure 8-1 is a flow diagram which shows the TLAA review task.

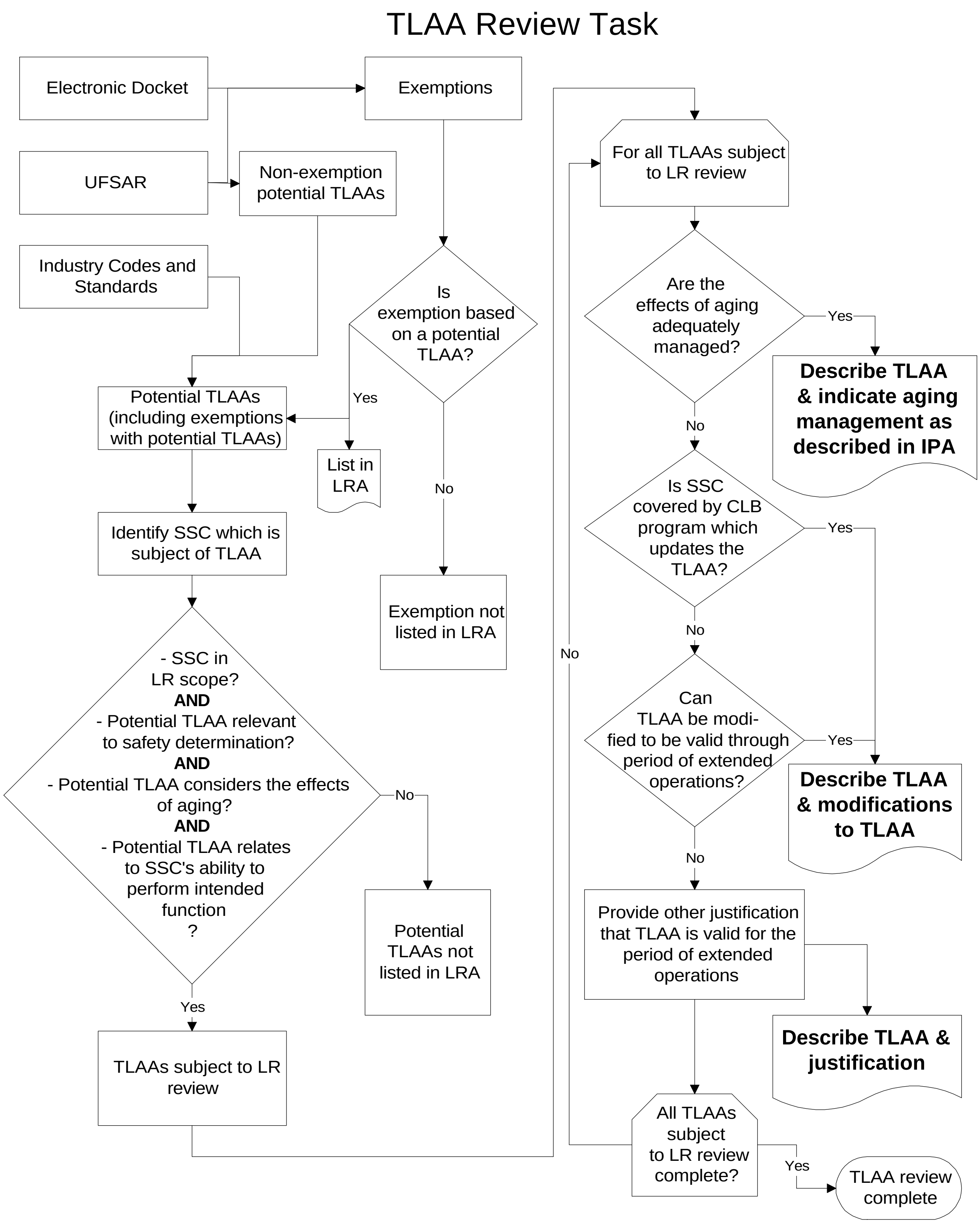
TLAA Review Task
Electronic Docket
Exemptions
UFSAR
Non-exemption potential TLAAs
Industry Codes and Standards
Is exemption based on a potential TLAA?
Yes
No
Potential TLAAs (including exemptions with potential TLAAs)
List in LRA
Identify SSC which is subject of TLAA
Exemption not listed in LRA
- SSC in LR scope?
AND
- Potential TLAA relevant to safety determination?
AND
- Potential TLAA considers the effects of aging?
AND
- Potential TLAA relates to SSC's ability to perform intended function ?
No
Yes
Potential TLAAs not listed in LRA
TLAAs subject to LR review
For all TLAAs subject to LR review
Are the effects of aging adequately managed?
Yes
No
Describe TLAA & indicate aging management as described in IPA
Is SSC covered by CLB program which updates the TLAA?
Yes
No
Can TLAA be modified to be valid through period of extended operations?
Yes
No
Describe TLAA & modifications to TLAA
Provide other justification that TLAA is valid for the period of extended operations
Describe TLAA & justification
All TLAAs subject to LR review complete?
No
Yes
TLAA review complete

Figure 8-1

Section 54.21(c)(2) of the LR Rule also requires a list of all exemptions granted under 10 CFR 50.12 which are determined to be based on a TLAA. These exemptions must be evaluated and justification provided for the continuation of the exemption during the period of extended operation.

> *(2) A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in §54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.*

The TLAA Review task also fulfills this requirement.

8.1 Identify Analyses to be Included in the Review

The first step in the TLAA Review task is a search of the CLB to identify potential TLAAs and exemptions. The CLB search is done by reviewing the CCNPP electronic docket and the UFSAR. The electronic docket contains the complete record of docketed correspondence between the NRC and BGE in an easily accessible computer format. The UFSAR is also searchable in the same format. Potential TLAAs, such as the aging analyses supporting the EQ Program, are identified by phrases indicative of time constraints such as "40 years," "32 EFPY" [effective full power years], and "qualified life." Exemptions are identified by using phrases such as "50.12," and "exemption." Specific examples of potential TLAAs contained in regulatory literature such as SECY 94-140 are reviewed in advance of the electronic search to help focus the search for potential TLAAs.

The potential TLAAs identified above are supplemented by a further search of the electronic docket. Codes and standards which govern design of SSCs at nuclear power plants were reviewed as part of a joint industry effort to determine those that might contain some form of TLAA. An additional search of the CCNPP electronic docket and UFSAR is performed using this list of codes and standards as the input queries. Any commitments to or reliance on one of the codes and standards with potential time dependencies are also included on the list of potential TLAAs.

Exemptions that are based on time limited aging analyses, the potential TLAAs identified through time related queries and the potential TLAAs identified through codes/standards queries comprise the complete set of potential TLAAs identified in this step.

8.2 Review of Potential TLAAs

The potential TLAAs are reviewed to determine if they affect an SSC in the IPA scope, to determine whether the analyses are relevant to a safety determination, to determine whether the analyses consider the effects of aging and to determine whether the analyses relate to the ability of the SSC to perform its intended function(s). The potential TLAAs which meet the first four criteria[12] are the TLAAs subject to LR review; i.e., those which must be listed in the LRA.

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[12] The definition of a TLAA contains six criteria. The two criteria not addressed in this step were already addressed in the initial search technique. The fact that the electronic search was performed against the CCNPP electronic docket and UFSAR implements the criterion that TLAAs be included in or incorporated by reference in the CLB. The time-related queries and the evaluations of codes and standards account for the criterion that TLAAs be related to assumptions regarding the period of the initial license, i.e., 40 years.

8.3 Disposition of TLAAs Which are Subject to LR Review

This step in the TLAA Review task compiles the TLAA-related information for the LRA. Because of the definition of TLAA and the requirements of 54.21(c), there is a definite relationship between a TLAA and the IPA results for the same SCs.

8.3.1 Relationship Between the IPA and TLAAs

In some cases, it may be possible to credit the same aging management programs and activities in the TLAA evaluation as were credited in the IPA. The IPA requires a demonstration that the effects of aging are adequately managed for all SCs within the scope of LR that are passive and long lived. 54.21(c) allows three options for addressing TLAAs, one being a demonstration that the effects of aging are adequately managed for the SCs affected by the TLAA. The definition of TLAA provides that only analyses affecting SCs within the scope of LR are defined as TLAAs. Therefore, if the IPA is able to demonstrate that the effects of aging associated with the TLAA are adequately managed during the period of extended operations for a set of SCs, it follows that the requirement under 54.21(c) would also be satisfied. (The requirements are identical.)

If, on the other hand, certain aging effects associated with a TLAA are difficult or impossible to monitor directly, the IPA process may have demonstrated that the effects of aging would not prevent the intended function of the SC using an analytical approach. This approach may have involved extending the existing time-related analysis or substituting an alternate analysis, to demonstrate that the effects of aging would not prevent performance of the intended function during the period of extended operation. In either case, the requirements of 54.21(c) are still satisfied, since 54.21(c) allows extending the TLAA or justifying by analysis that the current analysis remains valid for the period of extended operation.

Therefore, for long-lived components supporting passive functions, the IPA process required by §54.21(a) will have documented that the effects of aging on these SSCs will be adequately managed. Thus, the only remaining step is to review the IPA results to ensure that the TLAA evaluation requirements are met.

8.3.2 Methods for Extending or Re-evaluating TLAAs

When, as a result of the factors discussed above, the decision is made to extend an existing analysis or justify that the existing analysis remains valid, the techniques used to extend or justify are specific to each time dependent issue. Where there is already a widely accepted practice (such as 10 CFR 50.61, 10 CFR 50.49 or ASME Code) which governs the TLAA, that process is used to re-evaluate or extend the analysis. For example, 10 CFR 50.61 describes the requirements associated with PTS. These requirements would be implemented to account for PTS during the period of extended operations.

Similar to the discussion in Section 6.3.5, if there is an outstanding generic issue associated with the re-analysis process, the SOC to the Rule (60 FR 22484) provides three options: 1) If the issue is resolved before LRA submittal, the resolution can be incorporated into the LRA, 2) A justification can be developed that the CLB will be maintained until a point in time when one or more reasonable options would be available to adequately manage the effects of aging. For this alternative, a description would be provided for how the CLB would be maintained until the chosen point in time and the options available in the future would be described in general terms. 3) A plant-specific program could be developed that incorporates a resolution to the aging issue.

8.4 TLAA Results and Documentation

The results of the TLAA Review task are:

- The list of TLAAs subject to LR review;
- The list of exemptions in effect that are based on TLAAs; and
- Either:
  - The evaluations which demonstrate that TLAAs remain valid or could be modified to remain valid for the period of extended operation, or
  - The demonstration that the effects of aging considered by the TLAAs are being managed.

These results are described in the LRA. Since the programs credited in this section will normally be identical to those credited in the IPA, little, if any, new information is expected to be added to the FSAR Supplement. More detailed records of the TLAA Review task are maintained onsite.

ATTACHMENT (1)

APPENDIX A - TECHNICAL INFORMATION
2.0A - RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION FOR THE INTEGRATED PLANT ASSESSMENT METHODOLOGY

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
1. General: **CLARIFY WHAT PARTS OF THE PREVIOUS IPA SUBMITTAL** are relied on in this Integrated Plant Assessment (IPA) methodology or are the same in this methodology? **ALSO, CLARIFY HOW** and where in this methodology Baltimore Gas and Electric Company (BGE) addresses the open and confirmatory items from the previous Draft Safety Evaluation Report if it is relied on.	None	Table (1) indicates where the resolution is to each of the 1993 Requests for Additional Information (RAIs) in the August 1995 version of the methodology, and how the section numbering of the 1993 submittal is related to the sections in the 1995 submittal.
2. General: Documentation: The methodology makes reference to the need to document the results of the analysis or screening steps. However, the degree of documentation or elements of documentation that will be prepared are not discussed in any substantive form. **PROVIDE ADDITIONAL DETAIL ON HOW THE RESULTS WILL BE DOCUMENTED.**	Yes	The Rule does not require that the results of scoping be submitted to the NRC. The first submittal product of the IPA is the list of SCs subject to aging management review (AMR) per §54.21(a)(1). Therefore, BGE does not believe it is appropriate to describe in this methodology the format of the scoping results. These results will be maintained onsite in an auditable and retrievable format. The documentation of the results of the Pre-Evaluation, AMR, and Commodity Evaluation steps are located in Sections 5.5, 6.4 and 7.3 respectively. The documentation of Time-Limited Aging Analysis (TLAA) results are discussed in Section 8.4, which is entitled "Summary." The title of this section will be revised to be consistent with the titles to other sections of the methodology which describe documentation.
3. General: Operating Experience/Generic Communication/ Industry Topical Reports: The methodology mentions the importance of operating experience yet it does not demonstrate how and where consideration of such operating experience is to occur. Such operating experience may be relevant in the identification of aging effects that should be managed and the identification of	None	We utilize operating experience throughout the scoping and IPA process. The method of using this experience is a reliance on the site process which incorporates operating experience into all aspects of plant documentation, maintenance and operation, currently proceduralized in NS-1-300 (see Tab 1). No special verification of such experience is needed for scoping or the IPA.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
non-safety systems that can impact a safety system. **PROVIDE ADDITIONAL INFORMATION** as to when and how operating experience is considered in the IPA. Further, **EXPLAIN HOW EXISTING PROGRAMS** resulting from responses to NRC generic communications would be factored into the IPA.		
Additionally, the report indicates that industry documents are reviewed for potential age-related degradation mechanisms (ARDMs). Sampling information in Appendix A found that BGE has referenced the Nuclear Management and Resources Council (NUMARC) industry report on the pressurized water reactor vessel internals for renewal in the second example, "Reactor Coolant System." However, BGE did not reference the NUMARC industry report on the pressurized water reactor containment in the first example, "Containment."		In the actual LRA submittals, more effort will be taken to ensure consistent use of references from section to section.
The information on page 4-2 (Section 4.3 of Appendix A) is referenced from the NUMARC industry report on the internals. However, sampling the potential ARDMs discussed, the staff found several unresolved items from the staff review of the subject industry report that are identified as not significant in the BGE example, such as stress corrosion cracking and creep (core shroud assembly). The information on page 3-1 through 3-5 (Section 3.1 of Appendix A) is not referenced from the NUMARC industry report on the containment. However, sampling the potential ARDMs discussed, the staff found		We use the industry reports as a source of information much the same as Electric Power Research Institute reports and Nuclear Plant Aging Research reports. In some cases, one or more of the generic conclusions of these reports do not apply to specific Calvert Cliffs SCs. In these cases, the non-applicable report would <u>not</u> be referenced for the corresponding conclusion in the detailed AMR Report and other more pertinent information sources would be used to make the required demonstration. Because of this, BGE does not believe that it is appropriate to describe how industry reports will be used in the methodology. It is not necessary to describe in the methodology, the aging management reports or the license renewal application (LRA) each

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
differences in information between the BGE report and the NUMARC report, such as aggressive chemical attack on concrete and inaccessible areas. These differences should be discussed. **DISCUSS THE USE OF INDUSTRY DOCUMENTS** such as the NUMARC industry reports for renewal. Also, discuss how BGE assesses whether it is within the bounds of these reports.		instance where a conclusion in an industry reference, such as an industry report, does not apply to Calvert Cliffs equipment.
4. General: The phrase "maintain the pressure boundary" is used repeatedly. **WHAT IS THE CRITERIA USED TO DETERMINE** when the pressure boundary is not maintained. Is there a difference between maintaining pressure boundary integrity and maintaining pressure boundary?	None	Criteria for maintaining a system pressure boundary vary from system to system and will be presented and documented on a system-by-system basis. We intended no difference between the term "pressure boundary" and "pressure boundary integrity" in this methodology. The terms are used interchangeably.
5. Page 7. For the definition of "passive" **REPLACE** "does not require motion" with "is performed without moving parts."	Yes	Baltimore Gas and Electric Company will make the requested change to the methodology.
6. Page 12, Section 2.3.4 states that, "techniques provide an equivalent level of assurance." **WHAT IS THE PURPOSE IN ASSURING THAT ALL TECHNIQUES PROVIDE EQUIVALENT ASSURANCE. HOW DOES THIS ASSURE THAT THE EVALUATION TECHNIQUES ARE TO PROVIDE** the necessary evidence that the findings of §54.29 can be supported?	Yes	All techniques presented in the methodology provide the demonstration necessary to support the finding of §54.29. The wording in Section 2.3.4 and in Section 7 will be revised accordingly.

NRC Comment	Methodology Change	BGE Response
7. Page 19, Section 3.3.1.1 states, "By relying on the Q-List Accident Shutdown Flow Sheets and Vital Auxiliaries Flow Sheets, SR SSs are identified, as well as all SSs that could fail and prevent the functioning of SR structures and components (SCs). This identification is not limited to first level, second level or any specific level of support equipment. Rather, the scoping is performed consistent with the Calvert Cliffs Nuclear Power Plant (CCNPP) Q-List Design Standard which was developed with the intent of identifying and controlling a similar scope of systems, SSCs to that defined by the first two criteria of 54.4." This statement indicates that the Vital Auxiliaries Flow Sheets in the Q-List have identified all non-safety-related (NSR) systems, structures and components (SSCs) whose failure could prevent satisfactory accomplishment of any of the functions identified in §54.4(a)(1). The Open Item in the Draft Safety Evaluation Report questioned how the previous methodology would identify a NSR SSC that provides supporting functions to another NSR SSC that is required for a SR SSC to perform its function. **Provide a discussion or an example from the Vital Auxiliaries Flow Sheets in the Q-List** to show that a NSR SSC that provides supporting functions to another NSR SSC that is required for a SR SSC to perform its function would be identified as within the scope of LR.	None	As stated in the methodology, the BGE Q-List controls all SSCs which meet §54.4(a)(1) and (2) as "safety-related" at Calvert Cliffs. It makes no distinction between the SSC which satisfy criterion §54.4(a)(1) versus (2). Therefore, any example provided is controlled as SR at Calvert Cliffs. We do not believe that including an example in the methodology that fits the situation described in this RAI would provide any additional clarification of how the scoping is conducted. The following example is provided for your information. Note that all four levels of cascading are controlled as SR at Calvert Cliffs. A certain heating, ventilation and air conditioning (HVAC) unit is a SR vital auxiliary because it maintains the environment in the control room and cable spreading room so that the Reactor Protective System and Engineered Safety Features Actuation Signal System can perform their required safety functions. The electrical cables and panels which supply power to these units are also included in the scope of LR because their failure would prevent the operation of the HVAC units which in turn could prevent the operation of the Reactor Protective System and Engineered Safety Features Actuation Signal System.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
8. Page 20, Section 3.3.2 states, "These evaluations are reviewed to identify SSs that are relied on to mitigate the subject plant event as well as any systems or structures whose failure would result in failure of other equipment to mitigate the particular event." **PROVIDE A DISCUSSION OR AN EXAMPLE** to show that a NSR system or structure (SS) that provides supporting functions to another NSR SS that is relied on to meet the regulated events in §54.4(a)(3) would be identified as within the scope of LR.	None	We do not believe that including an example in the methodology that fits the situation described in this RAI would provide any additional clarification of how the scoping is conducted. The following example is provided for your information. Note that both levels of cascading are NSR. The diesel-driven fire pump is required under 10 CFR 50.48. The description of how this pump must function to comply with this regulation includes the requirement to provide diesel fuel for the pump. Therefore, the diesel fuel oil system piping which provides the fuel oil to this pump is included within the scope of LR.
9. Page 31, Section 4.1.1 discusses system intended functions. However, it does not contain details of the current licensing basis (CLB) design loading conditions under which the system is required to function. A system may be required to have structural integrity under normal, upset, emergency, and faulted conditions in accordance with the CLB. For example, a system may be required to withstand a seismic event while another system, such as the fire protection shutdown system installed to ensure post-fire shutdown capability (Paragraph II.L.6 of Appendix R), may not be required to withstand a seismic event. The difference in the intended function based on the design conditions between these two systems could affect the aging management program for renewal. Thus, **THE**	None	The definition of intended function in §54.4(b) does not include any reference to design conditions under which a system must perform its intended function. Therefore, BGE believes that this RAI requests information not identified during the scoping step. As discussed further in subsequent RAI responses, we believe that the appropriate place to factor in the design conditions is during the assessment/analysis phase of the aging management strategy. During this phase, the effects of aging are assessed to determine whether they impact the ability of the structure or component to fulfill its intended function during all of the required conditions.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
CLB DESIGN LOADING CONDITIONS SHOULD BE IDENTIFIED AND SUBSEQUENTLY TRANSFERRED TO THE SC INTENDED FUNCTIONS FOR CONSIDERATION in developing aging management programs, as appropriate.		
10. Page 31, Section 4.1.1 discusses system intended functions. IT SHOULD INCLUDE A DISCUSSION RELATING TO REDUNDANCY, DIVERSITY, AND DEFENSE-IN-DEPTH. Where the plant's licensing basis includes requirements for redundancy, diversity, and defense-in-depth, the system intended functions include providing for the same redundancy, diversity, and defense-in-depth during the period of extended operation. For example, a system with two independent trains, according to the plant's CLB, has to perform the intended functions by each independent train.	None	The BGE methodology for scoping SSs does not recognize redundancy, diversity or defense in depth as functions. In addition, the BGE process does not allow exclusion of any SSCs based on redundancy, diversity or defense in depth arguments. Therefore, the suggested discussion is not needed in the methodology.
11. Page 31, Section 4.1.1 pressure boundary function SHOULD INCLUDE: (1) Sructural integrity under CLB design loading conditions, and (2) General Design Criterion 19, "Control Room," in addition to Part 100 when discussing adequate radiation protection.	Yes	The current definition of pressure boundary is quoted directly from the Calvert Cliffs Q-List Design Standard and BGE does not see the need to modify this definition for license renewal. Safety-related equipment must perform their intended functions as described in the CLB. A statement to this effect will be added to the first paragraph in Section 4.1.1.
12. Page 39, Section 4.3 shows the commodity groups. ARE CABLE TRAYS CONSIDERED PART OF A SPECIFIED COMMODITY GROUP?	None	Cable trays are in the component supports commodity evaluation.
13. Page 42, Sections 5.1.1 and 5.1.2, REPLACE the word "motion" with "moving parts".	Yes	We will make the requested change to the methodology.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
14. Page 43, Section 5.2, Determination of Long-lived: Replacement on performance or condition. The rule does not allow SCs to be determined to be short-lived (not long-lived) based on a condition monitoring program. The portion of the Statement of Consideration (SOC) that is referenced on page 43 is intended to clarify the agency's position that SCs are considered long-lived if they are subject to a condition monitoring program (and not subject to a replacement based on a qualified life or specified time period) and that these SCs are subject to an AMR. Additionally, the SOC indicates that an applicant can use replacement programs based on performance or condition that provides reasonable assurance that the functionality of that SC will be maintained. **THIS SECTION NEEDS TO BE REVISED TO BE IN COMPLIANCE WITH THE RULE OR A DISCUSSION NEEDS TO BE PROVIDED AS TO HOW THIS WOULD SATISFY THE REQUIREMENTS OF THE RULE**. Additionally, it is not clear what site documentation will be available that justifies that the three criteria of Table 5-1 are met. **PROVIDE ADDITIONAL INFORMATION EXPLAINING THE SITE DOCUMENTATION** that will exist for these determinations and the level of detail in this documentation.	Yes	The replacement on condition steps of Section 5.2 resulted from a BGE misinterpretation of the SOC (60FR22478). We will move the discussion of replacement on condition to a new Section 6.1.4 (including Table 5-1) and characterize these steps as another approach to performing an AMR without specifically addressing ARDMs. Based on the above change, the documentation to support this step will be changed to be consistent with the AMR process documentation.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
15. Page 50, Section 6.1.1 indicates that the pressure-retaining components in the diesel generator supporting equipment would be managed by the diesel generator performance and condition monitoring program. The staff does not believe that the performance and condition monitoring program ensures the structural integrity of these pressure-retaining components under CLB design loading conditions during the period of extended operation. **PROVIDE ADDITIONAL DISCUSSION TO DEMONSTRATE HOW STRUCTURAL INTEGRITY UNDER DESIGN LOADS IS ADDRESSED BY THE PERFORMANCE AND CONDITION MONITORING PROGRAM**.	Yes	The ability of SCs to perform their intended functions under all design conditions should be addressed during the assessment/analysis phase of the aging management program after the effects of aging are discovered. We agree that the discovery techniques available through performance and condition monitoring <u>may</u> require additional supporting evaluations or inspection to ensure that degradation of pressure-retaining components is discovered in a timely manner such that there is a reasonable assurance that the CLB is maintained. In these cases, BGE would develop a sampling inspection of selected pressure-retaining components. The inspection would be conducted prior to the period of extended operation to discover aging effects that might impact the intended functions under design conditions. The extent of follow-on inspections and/or other activities will be determined based on the results of the sampling inspections. Section 6.1.1 will be modified to include this discussion. Additionally, Section 6.3.3.4 will be expanded to include guidelines for establishing sampling inspections for LR consistent with the executive committee discussions on December 7, 1995.
16. Page 50, Section 6.1.1. In addition to the diesel generator supporting equipment, **WHAT OTHER COMPLEX ASSEMBLIES** whose only passive function is closely linked to active performance have been identified?	None	This process was also applied to the refrigerant loops of the Control Room HVAC System and the Auxiliary Building and Radiation Waste HVAC System.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
17. Page 51, Section 6.1.1, Criteria for use of performance and condition monitoring of complex assemblies as adequate aging management for passive function. One of the criteria is that the "complex assembly" be covered by the Maintenance Rule. **PROVIDE SPECIFIC EXAMPLES THAT DEMONSTRATE THE USE OF THIS CRITERION**. **INCLUDE THE TECHNICAL BASIS** for how the passive functions of that "complex assembly" would be preserved by existing Maintenance Rule programs.	Yes	The BGE methodology does not rely on the Maintenance Rule alone to manage the effects of aging. The methodology includes the Maintenance Rule as one factor among many in providing the required demonstration. The contribution of the Maintenance Rule to the IPA demonstration is primarily that the existing performance and condition monitoring programs would have a process which would require periodic assessment of their effectiveness and would lead to improvements in the programs, if needed. The methodology will be changed to clarify that the bullets on page 51 describe the circumstances when this approach should be applied, not the steps of the approach itself.
18. Page 51, Section 6.1.2 discusses component assemblies subject to refurbishment. It is not clear how the proposed approach addresses the pressure boundary function. For example, page 52 states, "The assembly components and subcomponents are inspected for signs of aging and other degraded conditions." **WORDS LIKE "INCLUDING THE PRESSURE-RETAINING BOUNDARY" SHOULD BE INSERTED AFTER THE WORD "SUBCOMPONENTS"** in this statement to indicate that the inspection includes looking for degradation in the pressure-retaining boundary. In addition, page 52 states, "The component assembly's intended functions are tested after the refurbishment." **CLARIFY THIS STATEMENT** because the intended functions are to be performed under CLB design loading conditions which may be difficult to simulate in a test.	Yes	We will add "including pressure boundary" as requested to the cited section of the methodology. The refurbishment activity specifically includes a direct visual observation of the effects of aging and includes a post-refurbishment test consistent with current industry practices and the CLB. The last bullet in Section 6.1.2 will be modified to reflect the above wording in place of "component assembly's intended functions are tested . . . ."

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
19. Page 52, Section 6.1.3, Long-Lived Environmental Qualification (EQ) components This section states that components having an EQ life of greater than 40 years are adequately managed by the EQ program. This is not an acceptable argument. **PROVIDE THE RATIONALE TO BE USED TO DEMONSTRATE FURTHER QUALIFICATION OF THESE COMPONENTS** for the extended period of operation. For example, how will the qualification of cables for the additional period of service life be demonstrated? Additionally, this section states that the EQ program requires that the component be reanalyzed to extend the qualified life. **THE NRC WILL GENERALLY NOT ACCEPT ANALYSIS IN LIEU OF TESTING** to determine the qualified life of components. Any one of the four methods in §50.49(f) is acceptable to extend the qualified life of a component.	Yes	The portions of the long-lived EQ components which are covered by the EQ program (organic materials) will be identified as a TLAA and evaluated as a TLAA. (See response to RAI 36.) The options for addressing this TLAA are discussed further in the BGE response to RAI 40. The portions of the long-lived EQ program which are not covered by the EQ program (e.g., valve bodies of solenoid valves) will be addressed in a separate IPA report which addresses the effects of aging using the process described in Section 6.2 of the methodology. Section 6.1.3 will be changed consistent with the above discussion.
20. Page 55, Section 6.2.3 indicates that the rationale for designating whether each ARDM is applicable or not is maintained onsite. This assessment is part of the aging review and **SHOULD BE DISCUSSED AS PART OF THE RENEWAL APPLICATION** to demonstrate how the requirements of §54.21(a)(3) are being met.	Yes	Baltimore Gas and Electric Company believes that the level of detail requested in this RAI is not required to be included in the LRA by the Rule and accompanying SOC. The SOC (60FR22479) states only that, "the demonstration must include a description of activities, as well as any changes to the CLB and plant modifications that are relied on to demonstrate that the intended functions will be adequately maintained despite the effects of aging in the period of extended operations." The requested rationale will be available onsite for detailed review by NRC Staff and for the use of plant personnel.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
		However, we will modify Section 6.2.3 to state that a listing of all potential ARDMs evaluated during the AMR will be included in the LRA section for each system, structure or commodity group.
21. Page 55, Section 6.3.1 states, "The first phase of a maintenance strategy is identification that detrimental effects of aging are or could be occurring." **TIE THE DISCUSSION ON "DISCOVERY" TO THE SC INTENDED FUNCTIONS UNDER CLB DESIGN LOADING CONDITIONS**. For example, a phrase like "affecting the structure and component intended functions under CLB design loading conditions" could be inserted after the word "aging" in the above statement. The remainder of the text should also be revised accordingly, such as Sections 6.3.2 and 6.3.3. This would avoid relying on inspections that would not discover aging effects before a loss of intended function under a CLB design load.	Yes	We believe that the ability of SCs to perform their intended functions under all design conditions should be addressed during the assessment/analysis phase of the aging management program after the effects of aging are discovered. This approach is consistent with the current functional evaluation and operability determination procedures (NO-1-106, see Tab 2) used at BGE for maintaining equipment functionality. Once the effects are discovered, a determination will be made of their impact on the ability of the affected components to perform their intended functions under CLB conditions. In order to clarify this point, we will add a statement to the introduction of Section 6.3 to state that one of the goals of aging management is to manage the effects of aging such that the intended functions are maintained consistent with the CLB. The paragraph will also clarify that each of the four phases of the maintenance strategy takes this goal into consideration when determining the adequacy of an existing or proposed program or activity. Additionally, 6.3.1(1) will be modified to state that discovery methods may require augmentation for LR to ensure that the effects of aging are discovered in a timely manner such that there is reasonable assurance that the CLB will be maintained.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
22. Page 55, Section 6.3.1 discusses "Discovery." **DOES THE METHODOLOGY CALL FOR THE SPECIFIC FREQUENCY** of the associated activities, such as inspections, to be described in the renewal application?	None	The methodology does not require inclusion of this level of detail in the LRA. Such information is available, where appropriate, in controlled documents maintained onsite.
23. Page 55, Section 6.3.1 states, "Monitoring and evaluating industry experience also serves as a discovery activity for managing aging since other plants may discover aging effects before CCNPP." Page 60 (Section 6.3.3.5) states, "Monitoring plant and industry experience therefore provides reasonable assurance that these ARDMs will be discovered before they severely affect intended functions at CCNPP." **THIS IS NOT CONSISTENT WITH THE REQUIREMENTS OF THE RENEWAL RULE**. The SOCs accompanying the renewal rule explicitly addresses how aging-related Generic Safety Issues (GSIs) and Unresolved Safety Issues (USIs), that is, those being tracked in NUREG-0933, will be treated in renewal (60FR22484). However, for other applicable aging effects, the applicant is expected to provide a demonstration that the effects of aging will be adequately managed to ensure the intended function for renewal. Monitoring industry experience to manage aging for renewal is similar to relying on the regulatory process to manage aging for renewal, which was a proposal considered during rulemaking to revise the rule but was not adopted in the final rule. Industry operating experience is important in identifying potential aging effects for evaluation in a renewal	Yes	As stated in the methodology, this is a technique used for "unknown, emerging and hypothetical ARDMs . . . ." It is not appropriate to take any other actions to manage such aging mechanisms unless and until the need for other actions is demonstrated and what actions would be effective are determined. We believe that this technique for managing such aging mechanisms does meet the requirements of the Rule and is the only reasonable technique under these circumstances. We will not eliminate this option from the methodology. However, to clarify the use of this forward-looking and proactive practice, we will modify Section 6.3.1(1) to state that this form of aging management is used as the sole means for unknown and theorized aging mechanisms. The discussion in Section 6.3.3.5 will be amplified to describe the manner in which monitoring industry experience contributes to a more complex aging management program.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
application. However, a renewal applicant cannot rely solely on monitoring future industry development in lieu of proposing adequate aging management programs in the renewal application. As permitted by the renewal rule, a licensee can modify the aging management programs for renewal to take advantage of future industry development following the requirements of §50.59 or §50.92 if the program is addressed by a technical specification or license condition. **DELETE THIS OPTION AS AGING MANAGEMENT FROM THE METHODOLOGY.**		
24. Page 55, Section 6.3.1 discusses "Assessment/Analysis." **DISCUSS HOW THE SC INTENDED FUNCTION UNDER CLB DESIGN LOADING CONDITIONS** would be factored into the assessment/analysis. Also, **VERIFY THAT THE ACCEPTANCE CRITERIA** would be included in the renewal application.	Yes	During the assessment/analysis phase of the maintenance strategy, the need for and the nature of required corrective actions are based on the effects of aging that are discovered, and their impact on the ability of the component to perform its intended function under all design conditions. (This a currently a requirement of site procedures [NO-1-106, see Tab 2]). The following statement will be added to Section 6.3.1(2) - "A safety or safety support system shall be capable of performing its specified safety function for accident prevention and/or mitigation as described in the CLB. Likewise, a system providing a function for a regulated event must be capable of performing that function under the conditions described in the CLB evaluation of the regulated event. The assessment/analysis phase incorporates such requirements in determining the need for and nature of corrective actions after abnormal or degraded conditions are discovered. One possible result of such assessment/analysis would be to repeat the discovery phase using an expanded

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
		sample size or using an augmented or improved technique for discovering and quantifying the extent of a particular aging effect." With respect to whether the acceptance criteria are included in the LRA, the methodology does not require inclusion of this level of detail in the LRA. Such information is available, where appropriate, in controlled documents maintained onsite.
25. Page 56, Section 6.3.1 discusses "Corrective Action." **IT SHOULD ALSO INCLUDE ROOT CAUSE DETERMINATION AND CORRECTIVE ACTIONS** to preclude recurrence.	Yes	We will revise the methodology to clarify that such activities are already required, when appropriate, under site procedures (QL-2-100, see Tab 3) in accordance with 10 CFR Part 50 Appendix B.
26. Page 58, Section 6.3.3.1 discusses plant programs relied on for renewal. It indicates that the inservice inspection program is one of the programs. Sampling the examples in Appendix A of the report found that the specific edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI inservice inspection program proposed for renewal is not identified. Because the ASME Section XI program can vary with code editions, **REVISE THE METHODOLOGY TO HAVE SPECIFIC CODE EDITIONS IDENTIFIED FOR RENEWAL PROGRAMS BEING EVALUATED.** Also **DISCUSS HOW THE METHODOLOGY WOULD ENSURE** the reliability of ultrasonic examinations as	Yes	We will revise the methodology to require the specific edition to an industry code to be included in the LRA where the code is credited as part or all of the aging management program. It is not appropriate to address the reliability of any specific program in the methodology. As stated in Section 6.4, BGE will demonstrate the adequacy of any credited aging

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
described in Appendix VIII of the ASME Section XI code.		management program in the specific system, structure or commodity aging management report, not in the methodology.
27. Page 58, second paragraph. **DEFINE THE CONTENT OF A "CONDITION MONITORING" PROGRAM** as discussed in this paragraph.	None	We believe the phrase is already well understood in the industry and needs no further definition in our methodology. Several examples of condition monitoring programs are included in Table 6-1 (e.g., eddy current testing, vibration monitoring, thermography . . . .).
28. Page 58, fifth paragraph. The report states that the LRA could include a commitment to implement a program or modification at an appropriate future date before or during the extended period of operation. **THE REPORT SHOULD REFLECT THAT FOR PROGRAMS** or modifications delayed until sometime during the extended period of operation and after the initial licensed term, a justification must be provided that the aging effects will be managed (or does not require management) until such implementation. Additionally**, THE REPORT SHOULD BE REVISED TO STATE THAT THE IMPLEMENTATION DATE OF FUTURE PROGRAMS OR MODIFICATIONS WILL BE SPECIFIED IN THE LRA.**	Yes	The methodology will be modified to clarify that justification must be provided for actions which will not be taken until after the beginning of the period of extended operations. With respect to implementation dates of future activities, the methodology does not require inclusion of this level of detail in the LRA. Such information is available, where appropriate, in controlled documents maintained onsite.
29. Page 59, Section 6.3.3.2 indicates that aging management could rely on less formal activities, such as plant tours by managers. **PROVIDE EXAMPLES ON HOW SUCH INCIDENTAL ACTIVITIES** can be relied on to manage aging to ensure intended functions.	Yes	The methodology will be revised to clarify that such techniques are intended to be complementary to other activities such as one-time inspections and represent a defense in depth approach to aging management. These less formal activities are recognized in Generic Letter 91-18 for observing plant operation and identifying degraded conditions.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
30. Page 60, Section 6.3.3.4, One-time inspections		
a) **THE REPORT NEEDS TO BE MODIFIED TO INCORPORATE THE FOLLOWING**. Where applicable, the staff will require that any proposed one-time inspections be performed before the end of the initial 40-year license. In this way the staff can assure itself that there are no significant aging concerns prior to operation beyond the initial licensed term. The staff may accept one-time inspections after the end of the initial licensed term if the licensee provides adequate evidence that the specific issue of concern will not be a problem up to that time.	Yes	The methodology will be modified to clarify this point.
b) The report states that the one-time inspection can be used to argue that the degradation is adequately managed. The staff believes that **THE CORRECT ARGUMENT SHOULD BE THAT THE DEGRADATION THAT IS OCCURRING WILL NOT RESULT IN LOSS OF THE COMPONENT FUNCTION** during the period of extended operation and, therefore, no additional aging management activities or programs are necessary.	Yes	The methodology will be modified as suggested.
c) The report also concludes that if industry experience in the interim resolves an aging issue, a one-time inspection would be canceled. The staff agrees that industry resolution of important aging issues will be valuable, however, **A DETERMINATION THAT THE INDUSTRY HAS RESOLVED AN ISSUE WOULD NOT RELIEVE AN APPLICANT OF A REQUIREMENT OR COMMITMENT** to perform an inspection. (See Comment No. 23 for options to modify aging	Yes	The methodology will be modified to clarify that if a commitment which has been previously made needs to be adjusted or canceled, the site commitment management process would be used to govern this activity.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
management programs.) d) Page 60 (Section 6.3.3.4) indicates that a one-time inspection may be completed before the submittal of the renewal application. It also indicates that if no significant degradation is found in the inspection sample, no program is needed other than documenting the inspection. **DISCUSS HOW THE RESULTS OF THIS EARLY ONE-TIME INSPECTION WOULD BE EXTRAPOLATED TO DEMONSTRATE THAT THE EFFECTS OF AGING WILL BE ADEQUATELY MANAGED FOR THE PERIOD OF EXTENDED OPERATION**.		The need to extrapolate the results of one-time inspections will depend on the results of the inspection. If the effects of aging are expected to be minimal and no effects are found, no extrapolation would be needed. In such cases, activities such as those described in Section 6.3.3.2 will serve to substantiate the results of the one-time inspections. Other "one-time" inspections could result in the development of a periodic inspection program if results warrant such activities. A discussion consistent with the above paragraph will be added to this section of the methodology.
31. Page 60, Section 6.3.3.4 gives specific examples of one-time inspection of certain SCs for renewal. Although the one-time inspection is a useful tool for renewal, the staff has not determined whether the cited SCs would be adequately managed for renewal by one-time inspections. For example, freeze-thaw of external concrete is weather condition related, and Alloy 600 materials have cracked in service. Because the review at this time is a methodology review, **BGE SHOULD REMOVE THE SPECIFIC EXAMPLES**. Similarly, on the same page, the report discusses how the one-time inspection sample may be selected. Again, the concept is useful, but **THE REPORT SHOULD NOT MENTION SPECIFIC COMPONENTS** such as "valves" and "Alloy 600" in the methodology.	Yes	We believe that the examples provided clarify the steps of the IPA and, therefore, should not be deleted. We are not requesting specific approval of the technical details of the examples as part of the review of this methodology. However, to ensure that examples are not misinterpreted, the specific example pertaining to stress corrosion cracking of Alloy 600 will be deleted.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
32. Page 62, Section 6.3.4 indicates that "Assessment," "Corrective Action," and "Confirmation" phases of the aging management are performed through the existing "site issue reporting" and "corrective action program." Describe how the existing site issue reporting and corrective action program would be sensitive to LR issues. For example, "Assessment" would contain acceptance criteria for evaluation to ensure LR intended functions. **DESCRIBE HOW THE SITE ISSUE REPORTING AND CORRECTIVE ACTION PROGRAM WOULD BE ALERTED TO THOSE** criteria, including NSR equipment that may not have attracted much attention before renewal.	None	None of the SSCs within the scope of LR are any more important because of LR. They are within the scope of LR because they perform important functions independent of LR. Consequently, controls are already in place for such components which ensure issues related to their ability to perform their intended functions are adequately addressed.
33. Page 62, Section 6.4 indicates that the renewal application would contain a description of the programs and activities that are relied upon to manage the effects of aging. Detailed justification of the adequacy of the programs will be maintained onsite. **THIS PROPOSAL COULD RESULT IN A RENEWAL APPLICATION WITHOUT SUFFICIENT DETAIL FOR AN NRC REVIEW**. The renewal application must describe the aging management programs and justify why the proposed programs, either existing or additional, are adequate for renewal. Detailed program procedures need not be included in the application. The place for a summary description of programs and activities for managing the effects of aging is the Final Safety Analysis Report supplement and not the renewal application. The documentation description needs to be revised accordingly.	Yes	Sections 6.4 and 7.3 will be modified to clarify that the LRA will contain a demonstration that the effects of aging are adequately managed, as well as a description of programs and activities which manage the aging effects. The detailed justification of the adequacy of each program or activity will continue to be maintained onsite in an auditable format. The discussion in Section 8.4 will also be adjusted as necessary to incorporate this concept.
34. Page 63, Section 7.0 addresses "Commodity Groups."	Yes	Section 7 will be modified to include only a description of the

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
Although the use of commodity groups is generally acceptable, Section 7.0 actually contains the specific aging management programs for these commodity groups. Because the report addresses the IPA methodology and the review at this time is on the methodology, the staff has not reviewed the aging management programs. **BALTIMORE GAS AND ELECTRIC COMPANY SHOULD RELOCATE SPECIFIC AGING MANAGEMENT PROGRAMS FOR COMMODITY GROUPS TO APPENDIX A AS EXAMPLES**. Aging management of commodities could follow the methodology in Section 6 of the report. Further, the need for Section 7 of the report is unclear. Page 63 (Section 7.0) creates potential confusion by calling some commodity evaluations "equivalent to entire IPA" and some evaluations "equivalent to just AMR." It seems that all of the commodity groups could be pre-evaluated in Section 5.3, including a discussion of any special steps which caused the "equivalent to entire IPA" and "equivalent to just AMR" distinction. Then, based on the above comment, **SECTION 7.0 MAY BE DELETED WITH THE SPECIFIC AGING MANAGEMENT PROGRAMS RELOCATED TO APPENDIX A**.		alternate process steps. The technical conclusions, which in some cases dictate the nature of the alternate process, will be presented in the individual LRA section on each commodity group.
35. Page 68, Section 7.2.1.2. For all non-EQ cables, in addition to thermal aging, potential **RADIATION HOT SPOTS SHOULD BE ACCOUNTED FOR** in the AMR for the cable commodity.	Yes	No radiation hot spots exist outside of containment and, therefore, radiation hot spots do not need to be considered for non-EQ cable. However, based on the BGE response to RAI 34, this technical detail will be included in the LRA section for this commodity rather than in the methodology.

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
36. Page 82, Figure 8-1 indicates that, for an evaluation that otherwise meets the definition of TLAA, a "yes" response to "Is SSC covered by CLB program which updates potential TLAA?" would make the evaluation not a TLAA. This is not consistent with §54.3. The CLB program could be a basis for re-evaluating the TLAA for renewal in §54.21(c), but not a basis for disposing of the issue as not a TLAA in 54.3. **THE REPORT NEEDS TO BE REVISED TO PROPERLY LABEL TLAAS.**	Yes	We will revise the methodology to move the cited TLAA step. Potential TLAAs which satisfy this criterion will be identified as TLAAs and listed in the LRA. This step will be used in the TLAA evaluation process as an aid in resolving the TLAA issue.
37. Page 83 Section 8.1 - What was the **RANGE OF SEARCHES USED TO IDENTIFY TLAAS**?	None	The range of TLAA searches will be provided in the TLAA submittal, not in the methodology. For your information, the searches which were used are provided in Tables (3), (4) and (5).
38. Page 84, Section 8.2 indicates that EQ is not a TLAA because of a CLB program called EQ. Similarly, the methodology does not call out the containment prestressed tendons as a TLAA requiring a re-evaluation in the renewal application (see page 3-5 of Appendix A).	Yes	With respect to the Section 8.2 statement regarding EQ, this statement will be deleted consistent with the BGE response to RAI 36.
Issues such as EQ, metal fatigue, and prestressed tendons are TLAAs in accordance with §54.3. The renewal rule in §54.21(c) specifically requires such issues to be re-evaluated to cover the period of extended operation. **RELIANCE ON A FUTURE PROCESS IN LIEU OF A RE-EVALUATION IN THE RENEWAL APPLICATION WILL NOT SATISFY THE REQUIREMENTS OF THE RULE**.	None	With respect to the items not identified as TLAAs in Appendix A, TLAAs are addressed in a separate aging management report. Additionally, the listing and evaluation results of TLAAs are provided in a separate section of the LRA.
The **METHODOLOGY NEEDS TO BE REVISED SO THAT ISSUES SUCH AS EQ, METAL FATIGUE, AND CONTAINMENT PRESTRESSED TENDONS WILL ALSO BE**	None	With respect to reliance on future actions, §54.21(c) and §54.29 do not require re-analysis of all TLAAs prior to submittal of the LRA. Paragraph 54.21(c) requires evaluation of the TLAAs and lists three equally acceptable

IDENTIFIED AS TLAAS.		actions for addressing TLAAs. The §54.29 finding states that TLAAs are identified and actions identified and have been taken <u>or will be taken</u> with respect to TLAAs.
39. Page 84, Section 8.3 indicates that all TLAAs subject to renewal review are necessarily affecting SSCs within the scope of renewal and, therefore, the IPA process would have managed aging of the long-lived passive SCs. Thus, the only TLAA issue to be reviewed is for active and short-lived SCs. Although the report correctly pointed out that TLAAs, by definition, affect the same SSCs within the scope of renewal, it is an over-simplification to say that the IPA will necessarily address the TLAAs. Time-Limited Aging Analyses generally address aging effects that are difficult to be directly monitored. For example, there are currently no acceptable non-destructive methods to measure the extent of embrittlement of a reactor vessel. Also, there are currently no acceptable non-destructive methods to measure the integrity of cables. Thus, in general, it may be unrealistic to rely on the IPA to completely address TLAAs. The **TLAA DISCUSSION NEEDS TO BE REVISED TO BETTER REFLECT THE AGING MANAGEMENT EXPECTATIONS.**	Yes	We will remove the methodology wording in Section 8.3 that causes the misconception that TLAAs associated with long-lived passive Systems, structures and components are categorically excluded from TLAA evaluation because of the IPA process. Instead, the section will include a discussion (similar to that presented in the following paragraphs) to explain in more detail the relationship between the IPA and the TLAA for these SSCs. The IPA requires a demonstration that the effects of aging are adequately managed for all SCs within the scope of LR that are passive and long-lived. Paragraph 54.21(c) allows three options for addressing TLAAs, one being a demonstration that the effects of aging are adequately managed for the SCs affected by the TLAA. The definition of TLAA provides that only analyses affecting SCs within the scope of LR are defined as TLAAs. Therefore, if the IPA was able to demonstrate that the effects of aging associated with the TLAA are adequately managed during the period of extended operations) for a set of SCs, it follows that the requirement under §54.21(c) would also be satisfied. (The requirements are identical.) If certain aging effects associated with the TLAA are difficult or impossible to monitor directly as suggested, the IPA process would have been unsuccessful in demonstrating that the effects of aging are adequately managed by a plant program. Instead, the IPA process would have chosen a

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
		more analytical approach, either by extending the existing time-related analysis or substituting an alternate analysis, to demonstrate that the effects of aging would not prevent performance of the intended function. In either case, the requirements of §54.21(c) would still have been satisfied, since §54.21(c) allows extending the TLAA or justifying by analysis that the current analysis remains valid for the period of extended operation. Thus, the only remaining step would be to review the IPA results to ensure that the associated TLAA requirements are also met.
40. Page 84, Section 8.3 does not provide a methodology on how the re-evaluation of TLAAs would be performed. The rule in §54.21(c) provides options in evaluating TLAAs. Take metal fatigue, as an example: A component would meet §54.21(c)(1)(i) if it has been designed for 200 fatigue cycles and is expected to see less than 200 cycles for 60 years. A component would meet §54.21(c)(1)(ii) if it has a fatigue "cumulative usage factor (CUF)" of less than 0.6 for 40 years, which would be less than unity if increased by 50 percent to cover 60 years. The option in §54.21(c)(1)(iii) would be evaluated case-by-case, such as ASME Section XI ongoing activities regarding management of components with cumulative usage factors that may have exceeded the code limit of unity. The **REPORT SHOULD EXPAND SECTION 8.3 TO DESCRIBE THE METHODOLOGY FOR RE-EVALUATING**	Yes	We believe that the actual techniques for reanalysis or extending an existing TLAA would be specific to each time-dependent issue. Where there is already a well defined, widely accepted practice (such as 10 CFR 50.61, 10 CFR 50.49 or ASME code) which governs the TLAA, we will continue to use that process to re-evaluate or extend the TLAA. Wording will be added to Section 8.3 to reflect this discussion. For example, 10 CFR 50.61 clearly describes the requirements associated with pressurized thermal shock. These requirements would be implemented to account for pressurized thermal shock during the period of extended operations. Because this regulation requires a submittal prior to LRA approval, the results of this analysis would be submitted and approved prior to LRA approval. If there is an outstanding generic issue associated with the re-

NRC COMMENT	METHODOLOGY CHANGE	BGE RESPONSE
TLAAS.		analysis process (such as for EQ), the SOC to the Rule (60FR22484) provides three options: (1) if the issue is resolved before LRA submittal, the applicant can incorporate the resolution into their LRA; (2) an applicant can justify that the CLB will be maintained until a point in time when one or more reasonable options would be available to adequately manage the effects of aging (for this alternative, the applicant would have to describe how the CLB would be maintained until the chosen point in time and generally describe the options available in the future); (3) an applicant could develop a plant-specific program that incorporates a resolution to the aging issue. For example, the requirements for extending a qualified life under the EQ Program are defined in §50.49 and supporting regulatory information. If as a result of current activities, a GSI is associated with EQ, BGE may chose option (2) above to resolve this TLAA. Reliance on the existing 40-year qualification would demonstrate that the CLB is maintained until the 40-year point. The regulatory documents related to the GSI already describe the alternatives which would be available to resolve the issue. Because the above discussion includes BGE's approach for TLAAs which are subject to a GSI or USI, a new Section 6.3.5 will also be added to the methodology to explain the BGE approach for aging management programs which are the subject of a GSI or USI.

TABLE (1)
Relationship Between Previous and Current Revisions of IPA Methodology Revision

1993 METHODOLOGY	1995 METHODOLOGY
Volume 1, Section 1: "Introduction" & Volume 2, Section 1: "Introduction."	Section 1: "Introduction."
Volume 1, Section 2: "Screening Methodology Basis and Overview." Volume 2, Section 2: "Component Evaluation Methodology Basis and Overview."	Section 2: "IPA Methodology Basis and Overview."
Volume 1, Section 3: "System Level Screening."	Section 3: "System Level Scoping."
Volume 1, Section 4: "Component Level Screening."	Section 4: "Component Level Scoping."
Volume 1, Section 5: "Component Evaluation and Component Aging Evaluation Tasks."	Deleted. This section in the previous methodology was a brief introduction to the next volume.
Volume 2, Section 3: "Component Evaluation."	Section 5: "Pre-Evaluation."
Volume 2, Section 4: "Component Aging Evaluation."	Section 6: "Aging Management Review", specifically 6.2 "Performing the Aging Management Review by Evaluating Aging Mechanisms." Section 6.1 was added to describe other methods for conducting the AMR.
Volume 2, Section 5: "Implementation Planning Overview."	Section 6.3: "Methods to Manage the Effects of Aging".
---------	Section 7: "Commodity Evaluations." This section describes six cases where the normal IPA process was modified to add efficiency to specific evaluations.
---------	Section 8: "Time Limited Analyses Review." This section describes the process for completing this new requirement in the revised LR Rule.

TABLE (2)
Resolution of NRC Review Items Associated with the 1993 IPA Methodology

NRC Review Item	Methodology Page		NRC Review Item	Methodology Page
RAI 1	2		RAI 22	No changes
RAI 2	3		RAI 23	No changes
RAI 3 (Conf Item 3)	15		RAI 24	35
RAI 4	Deleted reference to CLB/D throughout the methodology.		RAI 25	37
RAI 5	No changes		RAI 26	38
RAI 6 (Conf Item 1)	Section deleted from the methodology as requested.		RAI 27 (Open Item 1)	19 & 20
RAI 7	13		RAI 28	9 & 10
RAI 8	See response to RAI 6		RAI 29	Bracketed information was deleted as requested.
RAI 9	17		RAI 30	Terminology changes made for consistency throughout.
RAI 10	See response to RAI 6		RAI 31	2
RAI 11	No changes		RAI 32	Terminology changes made for consistency throughout.
RAI 12	See response to RAI 35		RAI 33	15, 29 & 30
RAI 13	16		RAI 34	13
RAI 14	19		RAI 35	Terminology changes made for consistency throughout.
RAI 15	18 & 19		RAI 36	No changes
RAI 16	See response to RAI 14		RAI 37	Definition deleted.
RAI 17	No changes		RAI 38	See response to RAI 4
RAI 18	No changes		RAI 39	22
RAI 19 (Conf Item 5)	21		RAI 40 (Conf Item 2)	22
RAI 20 (Conf Item 4)	21 & 34		RAI 41	No changes
RAI 21	No longer applicable due to rule change.		RAI 42	38 & 39

Note: Page numbers refer to the August 18, 1995 submittal of the BGE IPA Methodology. These page numbers will vary slightly in the marked up version of the methodology.

TABLE (3)
List of Search Criteria in CCNPP Electronic Docket 1968-92 & Updated Final Safety Analysis Report Revision 17 for Identifying Potential TLAAs During Plant-Specific Search

Search was performed using the first word within five words of the second word. For those with an asterisk, search was also performed using the second word within five words of the first word. Different forms of the words were included in the search using the "+" command.

plant/life
design/life
component/life*
fatigue/life*
fatigue/analysis*
fatigue/analyses*
fatigue/evaluation*
analysis/year
analyses/year
analysis/yr*
analyses/yr*
40/year or 40/yr
forty/year or forty/yr
license/term
license/period
license/life*
erosion/allowance*
corrosion/allowance*
EFPY
effective full power years (searched as complete phrase)
effective full power yr (searched as complete phrase)
life/limit
equipment/life
cycle/year
useful/life*
installed/life*
service/life*
qualified/life*
residual/life*
life expectancy (searched as complete phrase)
life of the plant (searched as complete phrase)

TABLE (4)
List of Search Criteria in CCNPP Electronic Docket 1968-92 & Updated Final Safety Analysis Report Revision 17 for Identifying Potential Based on Other Utility's Results

Search was performed using the first word within five words of the second word.

reactor/coolant/pump/flywheel/missile
RCP/flywheel/missile
pump/flywheel/missile
pump/flywheels/missile
flywheel
CE/topical/report
Combustion/Engineering/topical report
CEOG/topical/report
Bechtel/topical/report
vendor/topical/report
topical/report
topical/reports

TABLE (5)

POTENTIAL TLAAS ASSOCIATED WITH CODES, STANDARDS AND REGULATORY DOCUMENTS

CODE/STANDARD/ REGULATORY DOCUMENT	ISSUE DATE(S)	SSC	TLAA-ISSUE
10 CFR Part 50, Appendix G,		Reactor Vessel	Fracture Toughness
10 CFR Part 50, Appendix H		Reactor Vessel	Embrittlement-Neutron Fluence Limit
10 CFR 50.49		Electrical Components Instrumentation Controls	Resistance to Radiation Degradation Effects Aging Qualification Tests
10 CFR 50.61		Reactor Vessel	Embrittlement-Ductility
ACI 318	1971, 1983	Intake Structure Class 1 Structures Containment Offgas Stack and Flue Intake Canal Equipment Supports and Foundations	Loss of Prestress
ACI 349	1980 (1977)	Class 1 Concrete Structures	Loss of Prestress
AISC	1970 Seventh Edition	Class 1 Structures Spent Fuel Pool Liner Intake Structures Primary Containment Structure Reactor Vessel Supports Intake Canal	Fatigue
AISC	1970 Seventh Edition	Crane Rails	Fatigue
ANSI B31.1 B31.1.0	1967	Class 1, 2, 3 Piping Non-Nuclear Piping Hangers, Supports, Blind Flanges, Fittings	Fatigue Corrosion Embrittlement
ANSI B31.7	1969	Class 1, 2, 3 Piping Class 1 Hangers, Supports, and Snubbers Service Water Piping (Saltwater at BGE)	Irradiation Corrosion Fatigue

TABLE (5)

POTENTIAL TLAAS ASSOCIATED WITH CODES, STANDARDS AND REGULATORY DOCUMENTS

CODE/STANDARD/ REGULATORY DOCUMENT	ISSUE DATE(S)	SSC	TLAA-ISSUE
API 620	12/31/78 Revision 2 Sixth Edition	Condensate Storage Tanks	Settlement Corrosion
API 650	1979 Revision 3 Sixth Edition	Above Ground Oil Tanks Condensate Storage Tanks	Corrosion Settlement
ASME Section III Nuclear Vessels	1965 Edition	Reactor Vessel Steam Generator Pump Bodies Valve Bodies Pressurizer Accumulator Containment	Embrittlement Fatigue Corrosion
ASME Section VIII Division 1 Pressure Vessels	1968 Edition	Pressure Vessels Heat Exchanger Demineralizers Containment Accumulators Head Tanks	Corrosion
ASME Section VIII Division 1 Pressure Vessels	1968 Edition	Air Dryers	Corrosion
ASME Section XI Inservice Inspection	1983 Edition	Reactor Vessel Steam Generator Pressurizer Pumps Valves Supports Piping Core Structures	Fatigue Crack Growth Hydrotest Temperature
ASME Section III Division 2 (Code for Concrete Reactor Vessels and Containments)	1977	Concrete Containment	Loss of Prestress Settlement Fatigue

TABLE (5)

POTENTIAL TLAAS ASSOCIATED WITH CODES, STANDARDS AND REGULATORY DOCUMENTS

CODE/STANDARD/ REGULATORY DOCUMENT	ISSUE DATE(S)	SSC	TLAA-ISSUE
ASME Section III Nuclear Power Plant Components Division 1	1971 Edition	Reactor Vessel Steam Generator Pressurizer Accumulator Pumps Valves Piping Containment Classes 1, 2, 3 MC	Fatigue
ASME Section III Nuclear Power Plant Components Division 1	1971 Edition	Steam Generator Pressurizer Accumulator Pumps Valves Piping Containment Classes 1, 2, 3 MC	Embrittlement
ASME Section III Nuclear Power Plant Components Division 1	1971 Edition	Reactor Vessel	Embrittlement
ASME Section III Nuclear Power Plant Components Division 1	1971 Edition	Reactor Vessel Steam Generator Pressurizer Accumulator Piping Containment MC	Corrosion
ASME Section III Nuclear Power Plant Components Division 1	1971 Edition	Pumps Valves Classes 1, 2, 3	Corrosion
ASME Section III Nuclear Power Plant Components Division 1	1971 Edition	Reactor Vessel Steam Generator Pressurizer Accumulator Pumps Valves Piping Containment Classes 1, 2, 3 MC	Deterioration of Materials in Service

TABLE (5)

POTENTIAL TLAAS ASSOCIATED WITH CODES, STANDARDS AND REGULATORY DOCUMENTS

CODE/STANDARD/ REGULATORY DOCUMENT	ISSUE DATE(S)	SSC	TLAA-ISSUE
AWS D1.1	1975	Class 1 Structures (steel) Reactor Vessel Supports Pipe Whip Restraints and Jet Impingement Shields Hangers and Supports	Fatigue
AWWA D100	1973	CST	Corrosion
AWWA D100	1973	Reservoirs	Corrosion
EJMA	1969 3rd Edition	Bellows	Fatigue Corrosion
IEEE-317	1976	Electrical Penetration Assemblies	Qualified Life
IEEE-323	1974	Class 1E Electrical and Instrumentation Equipment in Harsh Environments	General Aging
IEEE-334	1974	Motors	Aging Simulation Motor Life
IEEE-382	1972, 1980	Safety-Related Valve Actuators	Qualified Life
IEEE-383 (ANSI N41.10)	1974	Cables, Splices, Connectors	Environmental Aging
NUREG-0800 SRP 3.6.2	June 1987	Class 1 Piping	Pipe Rupture Locations
NUREG-0800 SRP 8.2	June 1987	Circuit Breakers	Life Cycle Operability
NUREG-0800 SRP 3.6.1	June 1987	Class 1 Piping	Fatigue
NUREG-0800 SRP 3.7.3	June 1987	Conduits Tunnels Buried Piping	Soil Settlement
NUREG-0800 SRP 3.8.2	June 1987	Steel Containment	Fatigue
NUREG-0800 SRP 3.9.1	June 1987	Reactor Coolant Pressure Boundary	Fatigue
NUREG-0800 SRP 3.9.3	June 1987	Snubbers (Piping Supports)	Evaluation of Fatigue Strength
NUREG-0800 SRP 3.9.4	June 1987	Control Rod Drive System	Life Cycle Operability

TABLE (5)

POTENTIAL TLAAS ASSOCIATED WITH CODES, STANDARDS AND REGULATORY DOCUMENTS

CODE/STANDARD/ REGULATORY DOCUMENT	ISSUE DATE(S)	SSC	TLAA-ISSUE
NUREG-0800 SRP 3.11	June 1987	Class 1E Equipment	Equipment Qualification
NUREG-0800 SRP 5.3.1	June 1987	Reactor Vessel	Material Surveillance of Vessel
NUREG-0800 SRP 5.3.2	June 1987	Reactor Vessel	Material Surveillance of Vessel
NUREG-0800 BTP MTEB 5-2, B.1.2	June 1987	Reactor Vessel	Fracture Toughness
NUREG-0800 BTP MTEB 5-2, B.3.2	June 1987	Reactor Vessel	Fracture Toughness
NUREG-0800 SRP 5.3.2	June 1987	Reactor Vessel	Fracture Toughness
NUREG-0800 SRP 6.1.1	June 1987	ECCS Components	Corrosion
NUREG-0800 SRP 6.1.1	June 1987	MSIV Actuators	Corrosion
Regulatory Guide 1.121 Revision 0	August 1976	Steam Generator Tubes	Fatigue
Regulatory Guide 1.131 Revision 0	August 1977	Class 1E Electric Cables	Qualification Testing
Regulatory Guide 1.154 Revision 0	January 1987	Reactor Vessel	Operation Under Pressurized Thermal Shock Situation
Regulatory Guide 1.35.1 Revision 0	July 1990	Concrete Containment Structures	Loss of Prestress
Regulatory Guide 1.89 Revision 1	June 1984	Safety-Related Electric Equipment	Requalification of Electrical Components
Regulatory Guide 1.90 Revision 1	August 1977	Concrete Containment Structures	Loss of Prestress
Regulatory Guide 1.99 Revision 2	May 1988	Reactor Vessel	Embrittlement

2.1 Time-Limited Aging Analyses

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing time-limited aging analyses (TLAAs). The TLAAs were evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

2.1.1 Introduction

As required for the LRA, BGE has identified and evaluated analyses in the current licensing basis (CLB) which may be valid only during the original 40-year license. These TLAAs are defined in 10 CFR 54.3 as:

. . . those licensee calculations and analyses that:

1) *Involve systems, structures, and components within the scope of license renewal, as delineated in §54.4(a);*
2) *Consider the effects of aging;*
3) *Involve time-limited assumptions defined by the current operating term, for example, 40 years;*
4) *Were determined to be relevant by the licensee in making a safety determination;*
5) *Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in §54.4(b); and*
6) *Are contained or incorporated by reference in the CLB.*

This definition was clarified by Statements of Consideration accompanying issuance of the License Renewal Rule. An analysis is relevant to license renewal if it provides the basis for a safety determination and, in the absence of the analysis, a different conclusion may have been reached.

The License Renewal Rule Section §54.21(c)(1) requires a list of TLAAs (as defined above) be provided in the LRA. The TLAAs were identified through a search of the CLB by performing a keyword search of BGE's electronic files of docketed correspondence and the Updated Final Safety Analysis Report (UFSAR). A list of potential TLAAs was developed using words and phrases indicative of time constraints. This initial list was supplemented by a further search using a list of codes and standards governing design of systems, structures, and components at nuclear power plants as the input query. Potential TLAAs thus identified were then screened to determine whether they met the definition presented in 10 CFR 54.3.

Section §54.21(c)(1) also requires the license renewal applicant to demonstrate that one of the following is true for each TLAA:

1) *The analyses remain valid for the period of extended operation;*
2) *The analyses have been projected to the end of the period of extended operation; or*
3) *The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.*

The TLAAs that were determined to be subject to license renewal review were evaluated in order to demonstrate that each analysis will meet one of the three conditions listed above. The demonstration of how each TLAA meets one of these three criteria is provided in Section 2.1.3 below.

The BGE IPA Methodology and associated NRC Safety Evaluation Report define the process used at CCNPP to satisfy the requirement to evaluate TLAAs for license renewal. [Reference 1] Upon applying this process, only one TLAA, the main steam piping fatigue analysis discussed in Section 2.1.3.4 below, has been demonstrated to meet Criteria 1 above. Criteria 2 has been demonstrated true for 6 out of 14 TLAAs, including the analyses related to irradiation embrittlement of the reactor vessel. In accordance with §54.29(a) of the License Renewal Rule, TLAAs that meet Criteria 2 have either been projected, or will be projected, through the period of extended operation. For those TLAAs that will be projected, BGE states in Section 2.1.3 below when those actions will be completed. Criteria 3 has been demonstrated true for the remaining TLAAs. These remaining TLAAs have been evaluated as part of the IPA for systems, structures, and components, which also requires a demonstration that the effects of aging are adequately managed. For these cases, a ”pointer” to a distinct section of the BGE LRA where the TLAA is evaluated is provided in Section 2.1.3 below.

Section §54.21(c)(2) of the License Renewal Rule requires that the license renewal applicant provide a list of all exemptions granted under §50.12 that are determined to be based on TLAA. Exemptions are discussed in Section 2.1.4 below.

2.1.2 List of TLAAs

Table 2.1-1 presents a summary list of the TLAAs identified in the CLB. It identifies the analysis involved, the section number in the BGE LRA where additional detail is provided, the subject area of the TLAA(s), and the disposition of the TLAA. [Reference 2, Table 5-1]

2.1.3 Demonstration of TLAA Dispositions

2.1.3.1 Environmental Qualification

The Environmental Qualification (EQ) Program is identified as a TLAA for the purposes of License Renewal. The TLAA aspect of EQ encompasses all long-lived equipment in the scope of the EQ Program, whether active or passive. At CCNPP, each EQ File for a group of long-lived components includes a qualified life calculation that is considered a TLAA. [Reference 2, Appendix A]

Environmentally-qualified equipment is replaced with qualified new equipment prior to the end of its qualified life. Preventive maintenance is scheduled to initiate and execute these replacements. Qualified life re-evaluations are an ongoing activity and consider actual normal operating conditions as compared to design maximums (e.g., actual ambient temperatures are below the maximum design temperature that was used as the basis for the current qualified life). Qualified lives are adjusted up or down accordingly. Qualified life re-evaluations are performed now under the current EQ Program and will continue to be performed during the period of extended operation. Refer to Section 6.3 of the BE LRA, Environmental Qualification, for a demonstration of how the effects of aging on the intended functions of electrical equipment in the EQ Program will be adequately managed for the period of extended operation. [Reference 2, Appendix A]

Calvert Cliffs is a Division of Operating Reactors (DOR) Guideline plant. The BGE LRA does not change our CLB relative to EQ. Baltimore Gas and Electric Company has DOR Guideline, NUREG-0588, and

10 CFR 50.49 qualified equipment. Calvert Cliffs will continue to function in the period of extended operation as it does today relative to EQ, except as required by changes to regulatory requirements. Equipment that must be replaced due to the approaching end of its qualified life will be replaced in accordance with regulatory constraints associated with 10 CFR 50.49 Guidelines, NUREG-0588, or 10 CFR 50.49. Note that equipment qualified to the requirements of the DOR Guidelines or NUREG-0588 will not necessarily be replaced during the period of extended operation.

TABLE 2.1-1

LIST OF TLAAs

ANALYSIS	SECTION	AGING EFFECT
Each EQ file is a TLAA	2.1.3.1	EQ-related
Heatup and cooldown curves	2.1.3.2	Irradiation embrittlement
Power-operated relief valve setpoint for low temperature over pressurization		
Pressurized thermal shock analyses		
Reactor vessel fatigue analyses	2.1.3.3	NSSS* fatigue
Reactor Coolant System piping fatigue analyses		
Steam generator fatigue analyses		
Pressurizer fatigue analyses		
Pressurizer auxiliary spray line fatigue analyses		
Pressurizer surge line thermal stratification -(fatigue portion of the stress and fatigue calculations)		
Main steam piping to turbine driven auxiliary feedwater pumps fatigue analysis	2.1.3.4	Fatigue
Containment liner plate fatigue analysis	2.1.3.5	Fatigue
Prestress loss calculations	2.1.3.6	Prestress loss
Criticality calculation for the spent fuel pool	2.1.3.7	Loss of neutron absorption

* Nuclear Steam Supply System (NSSS)

2.1.3.2 Irradiation Embrittlement

This group of TLAAs concerns the effect of irradiation embrittlement on the reactor pressure vessel and how this mechanism affects analyses that provide operating limits or address regulatory requirements for CCNPP. These calculations use predictions of the cumulative effects on the reactor vessel from irradiation embrittlement. The calculations are based on periodic assessments of the neutron fluence and resultant changes in reactor vessel material fracture toughness.

Three analyses are affected by embrittlement concerns and are considered in these TLAAs:

(1) Pressurized thermal shock requirements (10 CFR 50.61, 10 CFR Part 50 Appendix G);

(2) Low temperature overpressure protection power-operated relief valve setpoints and administrative controls, (Technical Specification Figure 3.4.9-3);

(3) Plant heatup/cooldown (pressure/temperature or "PT" limit) curves (Technical Specification Figures 3.4.9-1 and 3.4.9-2).

The pressurized thermal shock analyses have been projected to the end of the period of extended operation. As described in Section 4.1.4.5.4 of the UFSAR and Section 4.2 of BGE's LRA, after the latest revision to regulations addressing the reference temperatures for pressurized thermal shock, BGE showed that both CCNPP reactor vessels will continue to meet pressurized thermal shock screening criteria for 60 years of operation. Baltimore Gas and Electric Company has also augmented its surveillance program to obtain embrittlement information that will bound the period of extended operation. As documented in a series of Safety Evaluation Reports, the NRC has concurred with this demonstration, noting that future test results may change this assessment. [Reference 3, Section 4.1.4.5.4; References 4, 5, 6, and 7]

Title 10 CFR Part 50, Appendix G, requires the calculation and use of operational pressure and temperature limits during plant heatups, cooldowns, and inservice hydrostatic tests. The plant heatup/cooldown curves and associated low temperature overpressure protection pressure setpoint curves in the plant Technical Specifications provide for overpressure protection during these operating modes. Currently, the Unit 1 curves are valid beyond 48 effective full power years, while the Unit 2 curves are valid to approximately 30 effective full power years. The Technical Specifications will continue to be updated either as required by 10 CFR Part 50, Appendices G and H, to assure the operational limits remain valid at the current cumulative neutron fluence levels, or on an as needed basis to provide appropriate operational flexibility.

2.1.3.3 NSSS Fatigue Analyses

Components in the NSSS are subject to a wide variety of varying mechanical and thermal loads that contribute to fatigue accumulation. The Reactor Coolant System components were designed in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section III, and the American National Standards Institute (ANSI) Standard USAS B 31.7, Nuclear Power Piping Code. These codes require the design analysis for Class I components to address fatigue and establish limits such that initiation of fatigue cracks is precluded. Portions of UFSAR Section 4.1 and the certified design specification identify the different design cyclic transients used in the fatigue analysis required by code for various major components of the Reactor Coolant System including the reactor vessel, Reactor Coolant System piping, steam generators, pressurizer, pressurizer auxiliary spray piping, and pressurizer surge line.

The CCNPP Fatigue Monitoring Program tracks the number of critical thermal and pressure test transients, and monitors the cycles and fatigue usage for the limiting components of the NSSS. Locations in these systems have been selected for monitoring for fatigue usage; they represent the bounding locations for critical thermal and pressure transients and operating cycles. In order to stay within the design basis, corrective action is initiated well in advance of the cumulative fatigue usage factor approaching 1.0 or exceeding the number of design cycles, so that appropriate corrective actions can be taken in a timely and coordinated manner.

Baltimore Gas and Electric Company's demonstration that the effects of fatigue on the intended function(s) of NSSS components will be adequately managed for the period of extended operation is provided in the following sections of the BGE LRA: Section 4.1, Reactor Coolant System; Section 4.2, Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System; and Section 5.2, Chemical and Volume Control System. The NRC staff concerns about fatigue for license renewal as identified in Generic Safety Issue 166, Adequacy of Fatigue Life of Metal Components, are also addressed in these referenced sections of BGE's LRA.

2.1.3.4 Main Steam Piping Fatigue Analysis

The main steam supply lines to the auxiliary feedwater pump turbines provide the system pressure boundary function and are subject to thermal loadings. According to the UFSAR Chapter 10A discussion, 21,999 rapid full temperature cycles have been considered. However, even if the number of assumed cycles were limited to 7000 equivalent full temperature cycles, which is much more limiting, this piping would have to be cycled approximately once every 3 days over an extended plant life of 60 years. Under current plant operating practices, the system is operated only occasionally during plant heatups and cooldowns, during plant transients, and for periodic (monthly) testing. Plant heatups and cooldowns are limited to 500 each, and reactor trips are limited to 400 over plant life. Monthly testing over 60 years would contribute another 720 cycles. These actual and potential cycles combined equal slightly more than 2000 cycles for the auxiliary feedwater steam supply. It is, therefore, unlikely that the 7000 assumed cycles will be approached during the period of extended operation. Thus, the existing analysis is considered to remain valid for the period of extended operations, and there is reasonable assurance that the intended function will be maintained. Generic Safety Issue 166 does not apply to the main steam supply lines to the auxiliary feedwater pump turbines. [Reference 2, Appendix C]

2.1.3.5 Containment Liner Plate Fatigue Analysis

American Society of Mechanical Engineers codes require that the containment liner material be prevented from experiencing significant distortion due to the thermal load and that the stresses be considered from a fatigue standpoint. The following fatigue loads were considered in the design of the liner plate: [Reference 3, Section 5.1.4.3]

- The annual outdoor temperature variation, assumed to be 40 cycles during the plant's 40-year life;
- The interior temperature variations during the startup and shutdown of the Reactor Coolant System, assumed to be 500 cycles; and
- Thermal cycling due to a loss-of-coolant accident, assumed to occur once during plant life. (Note: American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Paragraph 412(n), Figure N-415(A) and its appropriate limitations have been used as a basis for establishing allowable liner plate strains. Since the graph in Figure N-415(A) does not extend below ten cycles, ten loss-of-coolant accident cycles was used for the analysis.)

The design of the liner plate and penetration sleeves included consideration of thermal stress and fatigue for which there was an assumed number and severity of thermal cycles. Since this assumption was partly based on a 40-year operating life, the fatigue analyses must be reviewed to assure they remain valid during the period of extended operation. This review or re-analysis will be projected to the end of the period of extended operation by the year 2012. Generic Safety Issue 166 does not apply to the containment liner plate.

2.1.3.6 Containment Tendons Prestress Loss

The prestress on the containment tendons decreases over plant life as a result of elastic deformation, creep and shrinkage of concrete, anchorage seating losses and tendon wire friction, stress relaxation, and corrosion. The extent of these losses over the original expected plant life was predicted to verify the Containment design. Regulatory Guide 1.35 requires periodic monitoring of current prestress values to ensure that prestress loss predictions of the original design remain valid. For a complete discussion of the aging management review performed on the tendons for license renewal refer to Section 3.3A, Primary Containment, of the BGE LRA. Section 3.3A includes a discussion on the recent operating experience regarding the discovery of corrosion and hydrogen-induced cracking.

Tendon prestress losses are determined by measuring tendon lift-off force. Technical Specification 4.6.1.6.1 (Unit 1) establishes the surveillance schedule for measuring lift-off forces of selected tendons. This measurement is performed in accordance with Surveillance Test Procedure STP-M-663-1. Technical Specification Figures 3.6.1-1 (Hoop), 3.6.1-2 (Vertical), and 3.6.1-3 (Dome) provide the normalized lift-off forces required to be achieved during the surveillance test procedure as a function of plant service life after initial prestressing. These curves presently cover 40 years of plant life. (Note that these curves are not included in the Unit 2 Technical Specifications as the lift-off tests have not been required for that Unit.) These curves will be recalculated by the year 2012 to accommodate the projected 20-year period of extended operation.

2.1.3.7 Poison Sheets in Spent Fuel Pool

The criticality analyses for the Units 1 and 2 spent fuel pools credit the existence of poison (i.e., neutron absorbing) sheets located between spent fuel assemblies. The criticality calculations assume the neutron absorbing material has a minimum concentration of Boron-10. [References 8 and 9] If there was a reduction in the amount of neutron absorbing material to below that assumed, the calculation may become non-conservative.

The criticality analysis for Unit 1 contains an assumption of the boron concentration that accounts for a potential loss of boron carbide due to aging. This conservative assumption was made based on experiments showing that the Carborundum sheets that are installed in Unit 1 may experience a loss of boron content due to aging. Therefore, the Unit 1 analysis is considered a TLAA. [Reference 8] The neutron absorbing sheets installed in Unit 2 are constructed of a material called Boraflex. The Unit 2 criticality analysis does not contain any assumption of a loss of boron concentration due to aging and, therefore, is not considered a TLAA. [Reference 9]

The spent fuel pool contains high-density spent fuel storage racks that consist of a base structure supporting storage cells primarily fabricated from stainless steel. For Unit 1, a neutron-absorbing sheet, fabricated by The Carborundum Company and consisting of a boron carbide powder in a fiberglass matrix, is sandwiched between the inner and outer walls on the four sides of each storage cell. The original neutron absorbing-sheet was specified to contain a minimum concentration of 0.024 grams per square centimeter of Boron-10. [Reference 10]

The Unit 1 criticality analysis contains an assumption of the boron concentration that accounts for a potential loss of boron carbide due to aging. This conservative assumption was made based on experiments showing that the Carborundum sheets may experience a loss of boron content, following exposure to gamma radiation equivalent to 40 years of service and a spent fuel pool water environment, due to degradation of the matrix material in which the boron carbide is bonded. The loss of boron carbide reduces the Boron-10 concentration experienced by an average value of 15%, with the maximum reduction in Boron-10 concentration experienced by any single test sample being 19.2%. The criticality analysis accounted for this potential degradation by assuming a minimum concentration of 0.020 grams per square centimeter of Boron-10. Since the degradation rate used in the current analysis was based on a radiation exposure sufficient to accommodate at least a 40-year pool lifetime, it must be updated to reflect the total exposure for 60 years. This analysis is currently being updated and will accommodate the period of extended operation. A service life of 70 years will be demonstrated for the Carborundum sheets, which will permit at least 10 years of usage beyond the period of extended operation. The update will be completed by 1999. [References 8 and 10]

Baltimore Gas and Electric Company has performed an aging analysis for the poison sheets and has determined there are plausible aging mechanisms for both Units 1 and 2 at CCNPP. Baltimore Gas and Electric Company's demonstration that the effects of aging are being adequately managed for the period of extended operation is provided in Section 3.3E, Auxiliary Building and Safety-Related Diesel Generator Building Structures, of the BGE LRA. Operating experience with these poison sheets is also discussed in that section of the report.

2.1.4 List of Exemptions Based on TLAA

Section 54.21(c)(2) of the License Renewal Rule requires a list of all exemptions granted under 10 CFR 50.12 that are determined to be based on a TLAA. These exemptions must be evaluated and justification provided for the continuation of the exemption during the period of extended operation. Baltimore Gas and Electric Company found no exemptions that were based on a TLAA.

2.1.5 Conclusions

Baltimore Gas and Electric Company has identified and evaluated the TLAAs important to license renewal, in accordance with 10 CFR 54.21(c). This evaluation demonstrates that 1 out of the 14 TLAAs remain valid, 6 out of the 14 have been (or will be) projected to the end of the period of extended operation, and for the remaining 7, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

2.1.6 References

1. Letter from Mr. D. M. Crutchfield (NRC) to Mr. C. H. Cruse (BGE), dated April 4, 1996, Final Safety Evaluation (FSE) Concerning the Baltimore Gas and Electric Company Report Entitled, Integrated Plant Assessment Methodology

2. CCNPP License Renewal Technical Report, "Time Limited Aging Analysis Review Report," Revision 0, November 1997

3. CCNPP Updated Final Safety Analysis Report, Revision 21

4. Letter from Mr. D. G. McDonald, Jr. (NRC) to Mr. G. C. Creel (BGE), dated July 15, 1992, Response to the 1991 Pressurized Thermal Shock Rule, 10 CFR 50.61, Calvert Cliffs Nuclear Power Plant, Unit 1 (TAC No. M82504) and Unit 2 (TAC No. M82505)

5. Letter from Mr. D. G. McDonald, Jr. (NRC) to Mr. R. E. Denton (BGE), dated May 24, 1993, Response to the 1991 Pressurized Thermal Shock Rule, 10 CFR 50.61, Calvert Cliffs Nuclear Power Plant, Unit 2 (TAC No. M82505)

6. Letter from Mr. M. L. Boyle (NRC) to Mr. R. E. Denton (BGE), dated July 29, 1994, Request for Approval to Use Plant Specific Data for Reactor Vessel Fracture Toughness Analysis, Calvert Cliffs Nuclear Power Plant, Unit No. 1 (TAC No. M88316)

7. Letter from Mr. D. G. McDonald, Jr. (NRC) to Mr. R. E. Denton (BGE), dated January 2, 1996, "Updated Valves for Pressurized Thermal Shock Reference Temperatures - CCNPP Units 1 and 2 (TAC Nos. M93230 and 93231)

8. Combustion Engineering Design Analysis A-CC1-FE-0005, "Reanalysis of Calvert Cliffs Unit 1 Spent Fuel Pool Criticality Calculations," April 14, 1992

9. Combustion Engineering Design Analysis A-CC2-FE-0003, "Reanalysis of Calvert Cliffs Unit 2 Spent Fuel Pool Criticality Calculations," Revision 2, July 2, 1992

10. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. Robert W. Reid (NRC), dated January 15, 1980, "Spent Fuel Pool Modification Supplementary Information"

3.1 Component Supports

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing Component Supports. Component Supports have been evaluated as a "commodity" in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

3.1.1 Scoping

3.1.1.1 Component Supports Commodity Scoping

Component supports are associated with equipment in almost every plant system. They perform the same basic function, regardless of the system with which they are associated. For this reason, it was determined that a commodity evaluation of component supports would be more efficient to address these supports than evaluating them as part of each system aging management review (AMR). [Reference 1, Page 69]

A "component support" is defined as the connection between a system, or component within a system, and a plant structural member (e.g., the concrete floor or wall, structural beam or column, or ground outside the plant buildings). [Reference 2, Page 1-2] Supports for structural components are not "component supports" in this sense because any support for a structural component is itself a structural component.

Commodity Description/Conceptual Boundaries

As discussed in the CCNPP IPA Methodology section on commodity evaluations (Section 7.2), component supports are scoped using a process similar to the scoping process for structures, as follows. A generic list of component support types was developed by reviewing industry and plant-specific information, including Seismic Qualification Utility Group (SQUG) guidance, American Society of Mechanical Engineers (ASME) Section XI component support inspection documentation, and the CCNPP System Level Scoping Results. All component support types that provide support to plant components that are within the scope of license renewal are identified, and these component support types are listed as being within the scope of license renewal. [Reference 1, Page 69]

Systems having component supports addressed in this section are identified in Table 3.1-1. [Reference 2, Page 3-19] Component supports interface with the components they support in the listed systems, and they interface with the structural component to which they are attached. At this interface, if anchor bolts are used, there is overlap between the AMR for the component support and the AMR for the structural component. The structures AMR considered the effects of aging caused by the surrounding environment, while the component supports AMR considered the effects of aging caused by the supported equipment (thermal expansion, rotating equipment, etc.) as well as the surrounding environment. [Reference 2, Page 1-3] The evaluation for the aging effects of structures is found in the Structures Commodity Evaluation in Section 3.3 of the BGE LRA.

Supports for both the distributive portions of systems, such as piping and cable raceways, and system equipment items, are included in the scope of this section. The total population of component supports are grouped into four categories based on the items they support (piping; cable raceways; heating, ventilation and air conditioning [HVAC] ducting; and equipment) and then into 20 component support types.

Component support types are based on similarities of physical characteristics, loading condition, and environment. All categories and types are shown in Table 3.1-2. [Reference 2, Pages 1-2, 1-4, and 2-1]

Supports for the steam generators (other than snubbers) and reactor vessel are not included in this commodity evaluation but are addressed in Sections 4.1 and 4.2 of the BGE License Renewal Application, respectively. Supports for the spent fuel pool cooling demineralizer and filter vessels are unique and are also addressed separately in Section 5.18 of the BGE LRA. Supports for tubing are included in Section 6.4 of the BGE LRA. Jet impingement barriers and whip restraints that are relied upon in the CCNPP high energy line break analysis (Updated Final Safety Analysis Report [UFSAR] Chapter 10A) are evaluated for the effect of aging as part of the structure that houses these components, in Section 3.3. [Reference 2, Page 1-2]

Basic design basis information for certain supports is discussed in UFSAR Chapters 1 (Principal Architectural and Engineering Criteria for Design), 5 (Containment Structure, Design Criteria), 5A (Structural Design Basis), 6 (Engineered Safety Features Design Basis), and 10 (Steam and Power Conversion Systems).

TABLE 3.1-1

SYSTEMS WITHIN THE SCOPE OF LICENSE RENEWAL CONTAINING SUPPORTS WITHIN THE COMMODITY EVALUATION

(CCNPP system numbers are shown in parentheses)

(002) Electrical 125 Volt DC Distribution	(042) Circulating Water
(004) Electrical 4 kV Transformers and Busses	(044) Condensate
(005) Electrical 480 Volt Transformers and Busses	(045) Feedwater
(006) Electrical 480 Volt Motor Control Centers	(046) Extraction Steam
(008) Well and Pretreated Water	(048) Emergency Safety Features Actuation
(011) Service Water Cooling	(051) Plant Water
(012) Saltwater Cooling	(052) Safety Injection
(013) Fire Protection	(053) Plant Drains
(015) Component Cooling (CC)	(055) Control Rod Drive Mechanisms and Electrical
(017) Instrument AC	(057) Technical Support Center Computer
(018) Vital Instrument AC	(058) Reactor Protection
(019) Compressed Air	(060) Primary Containment (Heating & Ventilation)
(020) Data Acquisition Computer	(061) Containment Spray
(023) Diesel Fuel Oil	(062) Control Boards
(024) Emergency Diesel Generators	(064) Reactor Coolant
(026) Annunciation	(067) Spent Fuel Pool Cooling
(029) Plant Heating	(069) Waste Gas
(030) HVAC	(071) Liquid Waste
(032) Auxiliary Building and Radwaste Heating and Ventilation System	(073) Hydrogen Recombiner
(036) Auxiliary Feedwater	(074) Nitrogen and Hydrogen
(037) Demineralized Water and Condensate Storage	(077/79) Area and Process Radiation Monitoring
(038) Sampling System (Nuclear Steam Supply System)	(078) Nuclear Instrumentation
(041) Chemical and Volume Control	(083) Main Steam
	(097) Lighting and Power Receptacles

Scoped Structures and Components and Their Intended Functions

Because the component supports within the scope of license renewal support components that provide functions meeting §54.4(a) (1), (2), and (3), the supports were determined to have the following intended functions, that directly correlate:

- Provide structural support for systems and components required to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, and the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the 10 CFR Part 100 guidelines.

- Provide structural support for systems and components whose failure could prevent satisfactory accomplishment of safety functions for items identified in Part a above.
- Provide structural support for systems and components that are required for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout, if the component is credited in the plant-specific analysis for these events included in the current licensing basis (CLB). [Reference 2, Page 1-3]

The design loading conditions for component supports include factors such as dead loads, thermal loads, seismic loads, etc. Supporting information for loading conditions of specific supports is maintained onsite. [Reference 3, Appendix 5A; Reference 4]

Passive Intended Functions / Component Support Types Requiring AMR

Because the intended functions listed above are provided without moving parts or without a change in configuration or properties, they are passive intended functions. Therefore, all component supports within the scope of license renewal are also subject to AMR [except snubbers, which were excluded as active equipment by §54.21(a)(1)(i)]. [Reference 1, Pages 39 and 69] However, the snubber subcomponents that mount the snubber to the pipe or component and to the structural component are referred to as snubber supports, and are included within the scope of license renewal. The “snubber support” includes the subcomponents from the snubber pin connections to the structural component (wall, floor, beam), and from the other snubber pin connection to the pipe or component being supported. Table 3.1-2 provides the population of component support types requiring AMR. [Reference 2, Page 1-2, Table 3-1, Table 3-2]

TABLE 3.1-2

COMPONENT SUPPORT TYPES REQUIRING AN AMR

Component Support Group	Associated Systems (see Table 3.1-1 for system title)
Piping Supports	
Spring Hangers, Constant Load Supports, Sway Struts, Rod Hangers, and Snubber Supports (Note 1) Outside Containment	008, 011, 012, 013, 015, 019, 023, 024, 029 036, 037, 038, 041, 044, 045, 052, 053, 061 067, 083
Spring Hangers, Constant Load Supports, Sway Struts, Rod Hangers, and Snubber Supports (Note 1) Inside Containment	011, 013, 019, 036, 038, 041, 045, 052, 061, 064, 067, 074, 083
Piping Frames and Stanchions Outside Containment	008, 011, 012, 013, 015, 019, 023, 024, 029, 036, 037, 038, 041, 044, 045, 046, 051, 052, 053, 061, 067, 071, 074, 083
Piping Frames and Stanchions Inside Containment	011, 013, 019, 036, 037, 038, 041, 045, 046, 051, 052, 061, 064, 067, 071, 074, 083
Cable Raceway Supports	Cables are evaluated as commodity and not assigned to specific systems.
Trapeze, Cantilever, and Other Supporting Styles Outside Containment	
Trapeze, Cantilever, and Other Supporting Styles Inside Containment	
HVAC Ducting Supports	
Rod Hanger Trapeze Supports Outside Containment	030 032
Rod Hanger Trapeze Supports Inside Containment	060
Equipment Supports	
Elastomer Vibration Isolators	030 032
Electrical Cabinet Anchorage Outside Containment	002 004 005 006 011 012 017 018 019 020 024 026 030 032 036 038 041 048 052 055 057 058 060 062 064 073 074 077/79 078 097
Electrical Cabinet Anchorage Inside Containment	077/079
Equipment Frames and Stanchions (Instruments/Batteries) Outside Containment	002 008 011 012 013 015 019 023 024 029 030 032 036 038 041 042 044 045 052 060 061 067 069 083
Equipment Frames and Stanchions (Instruments) Inside Containment	013 038 041 045 052 064 073 083
Frames and Saddles (Tanks and Heat Exchangers) Outside Containment	011 012 013 015 019 023 024 029 036 038 041 052 061 064 067 069 083
Frames and Saddles (Tanks and Heat Exchangers) Inside Containment	041 052 064 073
Metal Spring Isolators and Fixed Bases Outside Containment	008 011 012 013 015 019 023 024 029 032 036 041 044 052 061 067
Metal Spring Isolators and Fixed Bases Inside Containment	060
Loss-of-Coolant Accident (LOCA) Restraints	064
Ring Foundations for Flat-Bottom Vertical Tanks	008 023 036 037 052

Note 1: Snubber supports include the hardware from the wall and piping/equipment to the snubber pin connections. The snubber itself is not subject to AMR.

3.1.2 Aging Management

The potential age-related degradation mechanisms (ARDMs) for component supports are identified in Table 3.1-3. Those ARDMs identified as plausible for a group of supports are noted by a check mark (✓) in the appropriate column. Those ARDMs that were evaluated, but determined to be not plausible for a particular group of supports, are marked "not plausible." Those ARDMs that were not evaluated for a group of supports, because they are not applicable to the group, are marked N/A. [Reference 2, Table 2-1]

For efficiency in presenting the results of these evaluations in this report, component/ARDM combinations were grouped together where there are similar characteristics and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. The following seven groups have been selected for component supports. Table 3.1-3 also identifies the group assigned to each support/ARDM combination.

Group 1 - Piping Supports: general corrosion of steel, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion of piping/component

Group 2 - Cable Raceway Supports, HVAC Ducting Supports, Equipment Supports: general corrosion of steel

Group 3 - Elastomer Vibration Isolators: elastomer hardening

Group 4 - Metal Spring Isolators and Fixed Bases (outside containment)/LOCA Restraints: loading due to rotating/reciprocating equipment

Group 5 - Frames and Saddles/LOCA Restraints: loading due to hydraulic vibration or water hammer

Group 6 - Frames and Saddles/Ring Foundation for Flat-Bottom Vertical Tanks: loading due to thermal expansion of piping/component

Group 7 - Frames and Saddles(inside containment)/LOCA Restraints: stress corrosion cracking of high strength bolts

For the component supports AMR, where ARDMs were determined to be plausible, an aging management strategy was selected that involves both methods to mitigate the effects of the plausible ARDMs and methods to discover their effects. For component supports, discovery methods involve two separate but complementary sets of activities. The first set of activities consists of baseline walkdowns or inspections that are conducted one time to determine whether the plausible ARDMs are actually occurring for the supports potentially affected. The second set of activities involves follow-on actions that occur repetitively. The nature of the follow-on actions is dictated by the results of the baseline inspection or walkdowns. For example, if no evidence is found that the plausible ARDM is occurring during the baseline inspection, the follow-on actions credited may consist of periodic, documented walkdowns by system engineers to ensure that this condition continues. If evidence of significant aging is found for certain groups during the baseline activities, follow-on actions consist of aging management activities that are formulated to address the condition discovered during the baseline inspection. Baseline and follow-on activities are discussed in more detail under each component support group heading. [Reference 2, Pages 6-1 through 6-3]

To serve as an adequate baseline activity, the entire population of supports in a given group does not have to be subject to baseline inspection. If those supports that were not inspected are similar in design, material, and environment to those that were inspected, the conclusion can be reached that an adequate baseline was conducted. If loading conditions, environmental conditions, or equipment design differ significantly from the supports that were included in the baseline activity, focused baseline inspections for aging will be conducted to adequately baseline conditions of such supports. [Reference 2, Page 6-4]

TABLE 3.1-3

POTENTIAL AND PLAUSIBLE ARDMs FOR COMPONENT SUPPORTS

Potential ARDMs	Piping Supports				Cable Raceway Supports		HVAC Ducting Supports	
	Spring Hangers, Constant Load Supports, Sway Struts, Rod Hangers, and Snubber Supports Outside Containment	Spring Hangers, Constant Load Supports, Sway Struts, Rod Hangers, and Snubber Supports Inside Containment	Piping Frames and Stanchions Outside Containment	Piping Frames and Stanchions Inside Containment	Trapeze, Cantilever, and Other Supporting Styles Outside Containment	Trapeze, Cantilever, and Other Supporting Styles Inside Containment	Rod Hanger, Trapeze Supports Outside Containment	Rod Hanger, Trapeze Supports Inside Containment
General Corrosion of Steel	✓ (1)	✓ (1)	✓ (1)	✓ (1)	✓ (2)	✓ (2)	✓ (2)	✓ (2)
Elastomer Hardening	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Loading Due to Rotating/ Reciprocating Machinery	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Loading Due to Hydraulic Vibration or Water Hammer	✓ (1)	✓ (1)	not plausible	not plausible	N/A	N/A	N/A	N/A
Loading Due to Thermal Expansion of Piping/Component	✓ (1) *	✓ (1) *	not plausible	not plausible	N/A	N/A	N/A	N/A
Stress Corrosion Cracking of High Strength Bolts	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible
Radiation embrittlement of steel	N/A	not plausible	N/A	not plausible	N/A	not plausible	N/A	not plausible
Thermal effects on steel	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible
Grout/concrete local deterioration	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible
Lead anchor creep	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible

✓ - Indicates plausible ARDM determination
* - Not plausible for snubbers supports

(#) - Indicates the group in which this structures and components/ARDM combination is evaluated
N/A - Not Applicable

TABLE 3.1-3 (continued)

POTENTIAL AND PLAUSIBLE ARDMs FOR COMPONENT SUPPORTS

Potential ARDMs	Equipment Supports										
	Elastomer Vibration Isolators Outside Containment	Electrical Cabinet Anchorage Outside Containment	Electrical Cabinet Anchorage Inside Containment	Equipment Frames and Stanchions (Instruments & Batteries) Outside Containment	Equipment Frames and Stanchions (Instruments) Inside Containment	Frames and Saddles (Tanks & Heat Exchangers) Outside Containment	Frames and Saddles (Tanks & Heat Exchangers) Inside Containment	Metal Spring Isolators & Fixed Bases Outside Containment	Metal Spring Isolators & Fixed Bases Inside Containment	LOCA Restraints	Ring Foundation for Flat-bottom Vertical Tanks
General Corrosion of Steel	✓ (2)	✓ (2)	✓ (2)	✓ (2)	✓ (2)	✓ (2)	✓ (2)	✓ (2)	✓ (2)	✓ (2)	✓ (2)
Elastomer Hardening	✓ (3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Loading Due to Rotating/ Reciprocating Machinery	not plausible	N/A	N/A	N/A	N/A	N/A	N/A	✓ (4)	not plausible	✓ (4)	N/A
Loading Due to Hydraulic Vibration or Water Hammer	N/A	N/A	N/A	N/A	N/A	✓ (5)	✓ (5)	N/A	N/A	✓ (5)	N/A
Loading Due to Thermal Expansion of Piping/ Component	N/A	N/A	N/A	N/A	N/A	✓ (6)	✓ (6)	N/A	N/A	not plausible	✓ (6)
Stress Corrosion Cracking of High Strength Bolts	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	✓ (7)	not plausible	not plausible	✓ (7)	not plausible
Radiation embrittlement of steel	N/A	N/A	not plausible	N/A	not plausible	N/A	not plausible	N/A	not plausible	not plausible	N/A
Thermal effects on steel	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible
Grout/concrete local deterioration	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible
Lead anchor creep	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible	not plausible

✓ - Indicates plausible ARDM determination (#) - Indicates the group in which this structures and components/ARDM combination is evaluated

N/A - Not Applicable

Group 1 - Piping Supports: general corrosion of steel, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion of piping/component

A wide variety of piping support types are installed in systems within the scope of license renewal depending on the design requirements of individual piping configurations. During the AMR, those piping supports that contain threaded fasteners in their load bearing path were evaluated separately from those without such fasteners because those with fasteners are potentially fatigue-damaged or loosened due to thermal expansion (except snubber supports) and vibration. Within each of these types, supports inside containment were evaluated separately from those outside since the environment in containment is typically more severe for aging and provides fewer opportunities for routine discovery of degraded conditions. Tables 3.1-2 and 3.1-3 show the resulting four groups of piping supports. [Reference 2, Pages 2-1 and 2-2]

Piping supports are subject to general corrosion, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion. Although these are different aging mechanisms, with different effects, they can be discovered in the same manner, i.e., by visual examination. Therefore, piping supports of all types are addressed in this section, and any discussion that applies only to a particular type is noted as such. [Reference 2, Page 2-6]

Group 1 - (Piping Supports - General Corrosion of Steel, Loading Due to Hydraulic Vibration or Water Hammer, and Loading Due to Thermal Expansion of Piping/Component) - Materials and Environment

Piping supports are constructed of structural steel. Piping supports are located inside the Containment Buildings and inside other climate-controlled buildings. [Reference 2, Page 2-1]

Inside Containment:

- The maximum design ambient air temperature is 120°F for normal conditions.
- The design ambient air relative humidity during normal plant operation is 50% at 120°F and 14.7 psia.

[Reference 5, Page 19]

In the other buildings:

- Ambient temperatures are controlled by plant ventilation systems, as specified in UFSAR Chapter 9. The plant ventilation systems are designed to provide minimum (winter) and maximum (summer) building air temperatures, as specified in UFSAR, Table 9-18. Certain areas are maintained by safety-related ventilation systems. The remaining areas are ventilated by non-safety-related ventilation systems and are maintained at or below the maximum design temperatures.
- There are no design humidity requirements for the plant areas outside containment.

[Reference 5, Pages 22 and 24]

Radioactivity Levels:

- The maximum fluence for component supports at CCNPP, other than perhaps the reactor vessel supports, is significantly lower than 6 x 10^{17} n/cm^2. Note that the reactor vessel supports are not included in the Component Supports Commodity Evaluation. (Based on recent industry reports, significant radiation [neutron] embrittlement degradation will not occur for steels exposed to fluences less than 6 x 10^{17} n/cm^2.)

[Reference 2, Page 2-10, Note 7]

Group 1 - (Piping Supports - General Corrosion of Steel, Loading Due to Hydraulic Vibration or Water Hammer, and Loading Due to Thermal Expansion of Piping/Component) - Aging Mechanism Effects

As shown in Table 3.1-3, general corrosion, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion are the ARDMs considered to be plausible for piping supports. [Reference 2, Page 2-6]

General corrosion is plausible for all piping supports because humidity levels in the plant could result in moisture coming into contact with the structural steel supports. During the plausibility determination, no credit is taken for the protective coating applied to these supports; however, this protective coating plays an important role in the aging management approach for piping supports. [Reference 2, Page 2-10, Note 1]

Loading due to hydraulic vibration or water hammer and thermal expansion is considered plausible for spring hangers, constant load supports, sway struts, and rod hangers because these types of supports have threaded fasteners in the load bearing path that could be loosened by such loading. Piping supports are designed to accommodate a broad range of loading conditions. However, over time, loading could result in degraded support conditions. [Reference 2, Pages 2-5 and 2-6]

For snubber supports, loading due to thermal expansion was determined to be not plausible because, by design, snubbers do not restrict movement due to thermal expansion. Loading due to hydraulic vibration or water hammer was determined to be plausible for snubber supports because snubbers do restrict these types of movement. [Reference 2, Page 2-11, Note 13]

Piping frames and stanchions are utilized in applications where loadings due to hydraulic vibration or water hammer and thermal expansion are known to exist. These loads occur due to system operations and are included in the design of the affected supports. While these ARDMs are known to occur, the aging effects are not expected to prevent the piping frames from performing their intended support function.

However, piping frames are also utilized in applications where hydraulic vibration or water hammer are not normally expected to occur. These loads are generally attributed to some sort infrequent system transient. Calvert Cliffs' operating experience, with respect to piping frame damage due to water hammer, includes an occurrence, in March 1989, in the Unit 1 Low Pressure Safety Injection (LPSI) piping due to a check valve slam transient. Although this water hammer event caused piping frame support damage, analysis showed that piping integrity was not compromised. This event is described in more detail below. [References 6 and 7]

Therefore, while hydraulic vibration or water hammer and thermal expansion have been observed, the aging effects are not expected to prevent the piping frames from performing their intended support function and these ARDMs are considered to be not plausible for this type of support. [Reference 2, Page 2-6]

The effects of general corrosion on piping supports would be a loss of support material and reduction in component support strength if the ARDM were allowed to progress unmanaged. The effects of loading due to hydraulic vibration, water hammer, and thermal expansion could initially be loosening of bolted or pinned connections, weld crack initiation and growth, component displacement or misalignment, concrete damage, and/or hanger setting drift. If these mechanisms were left unmanaged, the effects could progress to the point of reducing the amount of support afforded to the piping and/or allowing excessive motion of the supported piping. This failure of the piping supports' intended function could, in turn, lead to failure of the piping pressure boundary under CLB conditions. [Reference 2, Pages 2-3, 2-5, and 5-4]

Operating experience, with respect to water hammer events at CCNPP that have caused damage to piping supports, includes the following:

- On May 13, 1975, the Unit 1 reactor tripped on loss of main feedwater. Approximately 40 minutes after the trip, three water hammers were experienced in the feedwater piping as main feedwater was being re-established to the steam generators. [Reference 8]
- On May 19, 1976, a preoperational test was performed on Unit 2 to determine the effectiveness of the addition of standpipes to the new main feedring. With the reactor in Mode 3, steam generator level was decreased via the blowdown system. Thirteen minutes after securing blowdown, feedwater was introduced into the steam generator at 5% of rated flow via the main feedring. As the water level reached the feedring, water hammer occurred. [Reference 8]
- On March 17, 1989, while performing a test on a containment spray pump, a bent vertical support on the shutdown cooling portion of the LPSI suction piping was identified. The support damage was determined to be a result of piping loads due to water hammer. The root cause of the water hammer was traced to check valve slam of one of the LPSI pump discharge check valves. [References 6 and 7]

A review of the 1975 and 1976 events indicated that water hammer could occur following the initiation of Main Feedwater System flow when the steam generator level is below the feedring following a loss of main feedwater flow. In late 1978 for Unit 2 and mid-1979 for Unit 1, the steam generators were modified by installing non-reducing J-tubes on the top of the feedrings and covering the bottom exit nozzles. This reduced the possibility of a feedwater water hammer event by extending the period of time required for the feedring to drain once it is uncovered. In addition, operating procedures were changed to reduce the potential for water hammer. [References 8 and 9]

For the 1989 check valve slam water hammer event, corrective actions included establishment of a check valve slam evaluation project. The check valve slam project identified the LPSI System and the CC System as the systems most susceptible to check valve slam transients based on similarities in system configuration and system operating experience. Testing to determine transient pressure loads and detailed structural modeling and analysis of the LPSI and CC piping systems was performed to determine the adequacy of the supports and the piping. This analysis concluded that transient loads may exceed the support capacity for a number of supports since the original design did not account for check valve slam. The 22 most limiting supports (12 LPSI supports and 10 CC supports) were identified and subjected to extensive testing. From this sample, three Unit 1 LPSI supports and one Unit 2 LPSI support were determined to have damage attributable to check valve slam. No damage attributable to check valve slam was found on the CC System supports. Corrective actions for the affected supports included design analysis of piping stresses, to determine system operability, and an evaluation to determine the appropriate repairs and modifications to the affected pipe supports. The results of the piping stress analysis showed that piping integrity was not compromised. Design actions to address damage caused by water hammer included strengthening of these supports to withstand the re-evaluated forces from water hammer. [References 6 and 7]

In summary, CCNPP operating experience with respect to water hammer is that it has occurred in the past and these events have been evaluated as appropriate. Design modifications were made and operating procedures were changed to reduce the potential for water hammer or damage due to water hammer in the future.

Group 1 - (Piping Supports - General Corrosion of Steel, Loading Due to Hydraulic Vibration or Water Hammer, and Loading Due to Thermal Expansion of Piping/Component) - Methods to Manage Aging Effects

Mitigation:

To mitigate the effects of general corrosion, the conditions on the external surfaces of the component support must be controlled. Significant rates of corrosion only occurs when the component support comes in contact with moisture. Preventing direct and prolonged contact between metal surfaces and moisture is an effective mitigation technique for general corrosion. Therefore, to mitigate general corrosion, protective coatings ensure that the external metal surfaces of the component supports are not in contact with a moist, aggressive environment for extended periods of time. In addition, plant housekeeping practices that identify conditions such as degraded paint can be used to mitigate the effects of general corrosion. [Reference 2, Page 2-10, Note 1]

The effects of loading due to hydraulic vibration and thermal expansion have been minimized through proper support design. The effects of loading due to hydraulic vibration and water hammer are minimized through proper system operation. Loading due to hydraulic vibration or water hammer is only a concern due to the potential for off-normal operation and transients. Therefore, no additional specific measures to mitigate these ARDMs are needed.

Discovery:

The effects of general corrosion are detectable by visual inspection. The external metal surfaces of the component supports are covered by a protective coating, and observing that significant degradation has not occurred to this coating is an effective method to ensure that corrosion has not affected the intended function of the component support. Coatings degrade slowly over time, allowing visual detection during normal operations. Since the coating does not contribute to the intended function of the supports, observing the coating for degradation provides an alert condition that triggers corrective action prior to degradation that affects the support's ability to perform its intended function. The degradation of the protective coating or any actual corrosion that does occur can be discovered and monitored by periodically inspecting the supports and by carrying out corrective action as necessary.

The effects of loading due to hydraulic vibration, water hammer, and thermal expansion are detectable by visual observation of external conditions. The effects of excessive loading from hydraulic vibration, water hammer, and thermal expansion are observable in the form of loosening of bolted or pinned connections, weld crack initiation and growth, component displacement or misalignment, concrete damage, and hanger setting drift. These conditions would be readily observable during a visual inspection. [Reference 2, Page 5-4]

Therefore, adequate discovery techniques for component support aging need to include both a visual observation of the general condition of the protective coating of the supports, and examination for loose parts, loosened fasteners, deteriorated welds, component displacement or misalignment, concrete damage, and hanger setting drift.

Group 1 - (Piping Supports - General Corrosion of Steel, Loading Due to Hydraulic Vibration or Water Hammer, and Loading Due to Thermal Expansion of Piping/Component) - Aging Management Program(s)

Mitigation:

The external metal surfaces of the component supports are covered by a protective coating that mitigates the effects of general corrosion. The discovery programs discussed below ensure that the protective coatings of component supports are maintained.

Discovery:

For discovery, the level of aging management activity needed for each category of component supports is determined based on the condition observed during a baseline walkdown of a representative sample of supports of each category. Therefore, discovery activities are discussed in two categories, baseline activities and follow-on aging management activities. The as-found condition during the baseline walkdown dictates the level of follow-on aging management needed for the support type. [Reference 2, Pages 6-1 through 6-5]

The CCNPP Inservice Inspection (ISI) Program is based on References 3, and 10 through 15. Calvert Cliffs Technical Specification Surveillance Requirement 4.0.5.a requires that ISI of ASME Code Class 1, 2, and 3 components be performed in accordance with Section XI of the ASME Code. The CCNPP ISI Program Plan describes the inspections performed to satisfy these requirements. Requirements are provided for parts to be examined, examination frequency, methods, acceptance standards, and additional examinations. [Reference 2, Page 5-1] Component support examinations are performed in accordance with a CCNPP procedure that fulfills the requirements of Section XI. The result of each inspection is documented in an outage report. [Reference 2, Page 5-3]

The ASME Section XI ISIs for component supports include a visual examination of a prescribed sampling of the systems covered by this program. The visual examination contains the following elements that would detect the effects of aging-related degradation in a timely manner: [Reference 2, Page 5-2]

- A visual examination to determine the general mechanical and structural condition of the support; and

- A check for loose parts, debris, abnormal corrosion products, wear, erosion, corrosion, and loss of integrity of bolted or welded connections.

The ASME Section XI ISI examination methods include the following elements, which are performed during the visual examination, that ensure that excessive loading, regardless of its cause, is discovered in a timely manner: [Reference 2, Page 5-2]

- Measurement of clearances;
- Detection of physical displacement;
- Structural adequacy of supporting elements;
- Connections between load-carrying structural members; and
- Tightness of bolting.

American Society of Mechanical Engineers Section XI ISI requires inspections of piping supports at periodic intervals such that all piping supports of code class systems are inspected on a sampling basis once per inspection interval. Inspection intervals are established based on the requirements of an established industry code (i.e., ASME Section XI). The current inspection interval for CCNPP is 10 years. [Reference 2, Page 5-3]

The CCNPP ISI Program is adequate to manage the effects of aging in component supports within the program scope for the following reasons: [Reference 2, Pages 5-3, 5-4, and 5-5]

- The examination procedure requires that the component supports be checked for the effects of the following potential ARDMs: general corrosion of steel, and vibration or thermal expansion cycles (loosening of bolted or pinned connections, weld crack initiation and growth, component displacement or misalignment, concrete damage, and hanger setting drift).
- Inspections performed to date have identified deficiencies like those associated with aging degradation.
- The program requires that each support within the ISI Program be inspected at regular intervals; as evidenced by the relatively small number of support deficiencies found to date, it appears that the inspection interval (10 years) is adequate for detecting degradation.
- The program requires expansion of the inspection scope in the event that degradation of component supports is observed; this reduces the likelihood that widespread degradation is occurring without being noticed in other supports in the affected system or other systems with like supports.
- The outage reports prepared after each inspection period provide historical information for supports.

The ISI Program is subject to internal assessment activity both within the Materials Engineering and Inspection Unit and through the Site Performance Assessment Group. The ISI Program is recognized through these assessments as performing highly effective examinations and aggressively pursuing continuous improvements through monitoring industry initiatives and trends in the area of non-destructive examination. Additionally, the program is subject to frequent external assessments by the NRC, authorized Nuclear Inservice Inspector, and others.

Operating experience relative to the CCNPP ISI Program has been such that no site-specific problems or events have occurred that required changes or adjustments to the program. Changes that may have been made over the program's history have been in response to developments by the NRC or within the industry.

Specifically for component supports, operating experience relative to the ISI Program has revealed that it is effective in discovering age-related degradation and/or other conditions that, if unmanaged, could potentially compromise the intended function of the affected supports. For example, during the 1995 Unit 2 spring refueling outage, 428 components and their supports were examined. The ISI visual examinations revealed 13 supports with inservice or construction/installation deficiencies that included: 9 supports with missing or loosened fasteners; 1 support with improper clearance; and 3 supports with missing sight holes on sway struts. During the 1996 Unit 1 spring refueling outage, 491 components and their supports were examined. The ISI visual examinations revealed 16 supports with inservice or construction/installation deficiencies that included: 4 supports with missing or loosened items; 1 support with improper spring settings; 1 support with improper clearance; 1 support with a cracked weld; 2 supports with a missing sight hole; 1 support with a misaligned snubber; and 6 supports where the as-found condition did not agree with the component support sketch. Deficiencies found during the ISI visual examinations were either accepted by evaluation or repaired/replaced to bring them into conformance with their original design. [References 16 and 17]

Baseline Walkdowns

Table 3.1-2 shows there are 25 systems within the scope of license renewal that contain piping supports. The aging management approach for the piping supports in these systems included a baseline walkdown to establish if there are active ARDMs within each system. [Reference 2, Table 3-1]

Twelve of the systems within the scope of license renewal that contain piping supports are subject to ASME Section XI ISIs. Completed ISI activities serve as an adequate baseline activity to document the condition of piping supports for these 12 systems within the scope of license renewal that contain piping supports. [Reference 2, Table 3-1] The ISIs occasionally find loose bolts in hangers, which indicates that ARDMs of loading due to hydraulic vibration or due to thermal expansion are active in some systems. [Reference 2, Pages 6-6 and 6-7] In the event that degradation of component supports is observed, the ISI Program requires that the deficiency be corrected and that additional supports be inspected. [Reference 2, Pages 5-3, 5-4, and 5-5]

Thirteen of the systems within the scope of license renewal that contain piping supports are not subject to ASME Section XI ISIs. [Reference 2, Table 3-1] Therefore, additional sampling baseline walkdowns will be performed. [Reference 2, Page 6-6] These systems are:

Well and Pretreated Water	Plant Heating
Fire Protection	Demineralized Water and Condensate Storage
Compressed Air	Nuclear Steam Supply System Sampling System
Diesel Fuel Oil	Condensate System
Extraction Steam	Liquid Waste
Plant Water	Nitrogen and Hydrogen

Plant Drains

These walkdowns will consist of a sampling of the supports within the scope of license renewal for the 13 systems. The sample approach will be comparable to the approach required by ASME Section XI for piping supports of ASME Class 3 systems. The walkdown scope will include inspection on a sampling basis for corrosion and loose bolts, and will be documented using means such as field notes and photographs. These walkdowns will document the condition of the piping supports within the scope of license renewal for all piping support types except piping frames outside containment. If an active corrosion mechanism is found during the additional sampling baseline walkdowns for pipe hangers outside containment, then the inspection scope for that system would be expanded to piping frame supports outside containment. Once these additional walkdowns are completed, an adequate baseline condition assessment will have been completed. [Reference 2, Pages 6-6 and 6-7]

Although there is nuclear industry experience with respect to loose piping support concrete expansion anchor bolts (e.g., NRC Inspection and Enforcement [IE] Bulletin 79-02), additional baseline inspections specifically for anchor bolts are not considered necessary. The existing baseline activities are considered adequate and, as described below, failure of concrete expansion anchors is more of a design/installation issue rather than an aging issue.

To support the SQUG effort in the mid-1980s, the Electric Power Research Institute (EPRI) sponsored a research program to develop procedures and guidelines to demonstrate the adequacy of equipment anchorages for older nuclear plants. This work is documented in EPRI report NP-5228-SL, Revision 1.

Electric Power Research Institute report NP-5228-SL documents the compilation and analysis of extensive test data available on concrete expansion anchors. The report identifies three types of failure mechanisms associated with tension failures of concrete expansion anchors: (1) concrete cone failure, (2) anchor tension failure, and (3) anchor slip. These mechanisms are discussed as follows:

- Concrete Cone Failure – Concrete expansion anchors with deep embedment depth, adequate spacing between anchors, and adequate distance between the anchor and a free concrete edge do not exhibit this failure mode.
- Anchor Tension Failure – Anchor tension failure occurs when the tensile load exceeds the ultimate tensile strength of the anchor material prior to a concrete cone failure or the anchor slipping out of the hole.
- Anchor Slip – Anchor slip failures occur when the lateral pressure that the anchor exerts on the sides of the drilled hole crushes the concrete and opens the ring or sleeve sufficiently to allow the end of the cone expander to slip through the ring or sleeve. Note that concrete strength (which increases with time as a function of shrinkage, and according to American Concrete Institute standard 209R-82, 91% of the shrinkage occurs during the first year, 98% in 5 years, and 100% in 20 years) is an important consideration in the EPRI/SQUG guidelines for assessing anchorage adequacy.

Concrete expansion anchors fail under shear loadings either by a shear failure of the anchor bolt material or formation of a crack in the concrete.

All of these failure mechanisms are associated with the quality, including design, of the initial installation and/or the size of the load on the anchor. None of the failure modes is expected to be affected by age-related effects, such as anchor bolt relaxation or concrete shrinkage because:

- Bolt preload in the anchor is not counted on for anchor function. Once an anchor is "set" by torque, anchor function is maintained by the irreversible expansion of the anchor expansion ring or cone into the concrete.
- Anchor expansion into the concrete results in considerably larger displacements than would be expected for any credible concrete shrinkage, even over a long period of time.
- Loss of preload due to relaxation of the steel parts of the anchor is not expected at ambient temperatures.

Based on the above, the follow-on activities described below are deemed adequate to ensure that the anchor bolts will continue to perform their structural support function under CLB conditions during the period of extended operation.

An Age-Related Degradation Inspection (ARDI) Program, as described in the BGE IPA Methodology, will be implemented to address 24 specific inaccessible piping supports outside containment. These supports cannot rely on walkdowns for ongoing aging management for the effects of general corrosion, loading due to hydraulic vibration, or loading due to thermal expansion. These supports are included in the ARDI Program for inaccessible structural steel. Development of the ARDI Program includes the following steps: [Reference 2, Pages 6-6 and 6-7; Reference 18]

- Identification of inaccessible structural steel locations;
- Selection of representative components for inspection;
- Development of an inspection sample size;
- Selection of appropriate inspection techniques; and
- Development of requirements for reporting results and corrective actions if aging concerns are identified.

The inaccessible piping supports discussed above were originally identified as being inaccessible as part of the activities associated with NRC IE Bulletin 79-14 as described in a BGE letter to the NRC dated October 19, 1984. [Reference 18]. The letter stated that there were 24 piping supports outside containment inaccessible for inspection and testing, and provided information as to the location of those supports. One of the 24 supports identified in the letter, associated with the Unit 2 Service Water System, has been abandoned in place and replaced functionally with an accessible support. The abandoned support is located inside a concrete wall, the replacement support is located outside of that wall. Additionally, the letter stated that there were seven inaccessible supports located underwater in the Unit 1 Spent Fuel Pool. The current as-built design reflects that there are actually 11 inaccessible supports located underwater in the Unit 1 Spent Fuel Pool. However, there is a piping modification planned that will reduce this number to eight. Upon completion of this modification, there will be a total of 24 inaccessible supports, as originally reported.

These supports are inaccessible either because they are located underwater (in spent fuel pools or refueling water storage tanks), or because they are located in high radiation areas. It may not be possible to perform a visual walkdown of these supports, as was concluded by the IE Bulletin 79-14 efforts. However, other inspection techniques (e.g., remote video) may be recommended under the ARDI Program if they are viable. The ARDI Program will specifically either sample some of these supports (possibly using the remote inspection techniques), sample other accessible supports that are similar in design/environment, or will provide an analysis that will document why any inspection is not required.

The ARDI Program will ensure that age-related degradation is managed such that inaccessible component supports will be capable of performing their intended functions under all CLB conditions.

Follow-on Activities

Based on the results of baseline inspections completed per the existing ISI Program requirements, it was determined that continuing ASME Section XI ISIs into the period of extended operations will also serve as an adequate follow-on activity for those piping systems subject to that program. [Reference 2, Page 5-4]

For piping supports not covered by ISI requirements, the results of the additional baseline walkdowns described above will determine the extent of aging management practices needed for these supports. If the baseline walkdowns reveal no significant effects of aging from general corrosion, loading due to hydraulic vibration or water hammer, or loading due to thermal expansion, then the follow-on activities for aging management of these piping supports will be by system engineer walkdowns, CCNPP Administrative procedure, "Control of Shift Activities," (NO-1-200), and "Ownership of Plant Operating Spaces" Program (NO-1-107), discussed below. [Reference 2, Pages 4-2 and 6-6]

Calvert Cliffs Plant Engineering Guideline (PEG)-7, "System Walkdowns," provides for discovery of the effects of component supports ARDMs by providing for visual inspection of component supports during system walkdowns, reporting the walkdown results, and initiating corrective action. The program applies to mechanical and electrical systems; and includes visual inspections of mechanical, electrical, and instrumentation components, within each respective system. Under this program, inspection items typically related to aging management include identifying poor housekeeping conditions (such as degraded paint), and identifying system and equipment stress or abuse (such as thermal insulation damage, bent or damaged hangers, etc.). Excessive vibration, unusual noise, and excessive temperatures are some other symptoms of potential equipment stress that are considered. Conditions identified as adverse to quality are documented on Issue Reports in accordance with procedure QL-2-100, "Issue Reporting and Assessment." [Reference 19]

Under PEG-7, the system engineer performs periodic walkdowns; walkdowns before, during, and after outages; and walkdowns related to a specific plant modification(s). [Reference 19, Section 5.0] These walkdowns have the following general characteristics:

- Walkdowns are conducted at periodic intervals, as set by the PEG, based on system performance, operating conditions, etc.
- Walkdowns are performed by the assigned system engineer, who is familiar with the system and its condition. Signs of corrosion or effects of excessive loading would be detected by this individual.

- Conditions adverse to functionality, indications of system or equipment stress or abuse, safety or fire hazards, and housekeeping deficiencies are documented and an Issue Report is generated as required.

Specifically for piping supports, PEG-7 contains the following characteristics:

- Plant Engineering Guideline-7 contains a mechanical system walkdown checklist that contains items related to the condition of piping supports (in addition to other components, such as valves and pumps), on which to document adverse conditions observed during the walkdown.
- A CCNPP Engineering Standard, ES-002, "Pipe Support Inspections," has been prepared to detail acceptable and unacceptable conditions of piping supports. Excerpts from this standard are included in the system walkdown guideline as an attachment to PEG-7. [References 19 and 20]
- Plant Engineering Guideline-7 requires that any unusual condition observed during the system engineer's walkdown of piping supports be recorded on the walkdown sheet and assistance obtained from design engineering in evaluating the impact of the unusual condition. Conditions that warrant further action are documented on an issue report and the site corrective action program tracks the status of corrective actions. [Reference 19]

Plant Engineering Guideline-7 promotes familiarity with the systems by the system engineers and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. As a result of experience gained, PEG-7 has been improved over time to provide guidance regarding specific standard activities that should be included in walkdowns.

The Control of Shift Activities and Ownership of Plant Operating Spaces Programs ensure that aggressive conditions, such as pooled water, are not allowed to remain for extended time periods. [References 21 and 22]

Calvert Cliffs procedure NO-1-200 (based on References 3, 10, and 23 through 35) ensures that shift operations are conducted in a safe and reliable manner and within the scope of the operator's license, procedures, and applicable regulatory requirements. During normal operation, NO-1-200 directs plant operators to inspect operating spaces each shift and to report any deficiency. When shutdown, the containment is also inspected. The procedure lists detailed inspection guidelines, including discovery of items such as oil/water leakage, irregular noise and vibration levels, irregular temperature, and humidity for the area, etc. [Reference 21, Section 5.8.B] Site deficiencies are documented in accordance with QL-2-100 issue reporting and assessment procedure to ensure appropriate corrective action is taken. Operator rounds have been historically effective in identifying plant deficiencies. The documented guidance and expectations have been improved over the years as a result of lessons learned and the site emphasis on continual quality improvement.

Calvert Cliffs procedure NO-1-107 (based on Reference 36) provides requirements and guidance on personnel accountability for the correction of housekeeping, material and radiological deficiencies. This procedure assigns plant areas to an "owner." These owners are identified within each space and provide a point of contact for any individual who finds deficiencies or any concern with the space. Owners are required to periodically inspect their space for deficiencies defined in the procedure, including checking for leaks; loose or unbracketed pipes; loose, stripped, or missing fasteners; and corrosion, rust, or inadequate paint. Spaces subject to inspection include areas such as Containment, Turbine Building, Auxiliary Building, Intake Structure and outside areas. [Reference 22] The Ownership of Plant Operating Spaces Program is relatively new and no major changes to this program have been necessary to this point. Site deficiencies are documented in accordance with QL-2-100 to ensure appropriate corrective action is taken. [Reference 22, Section 5.2]

Official assessments of programs such as these that contribute to the plant's "housekeeping" (including NRC comments) have been historically noted as effective in identifying deficiencies in plant areas. [Reference 37]

For snubber supports, the Snubber Visual Inspection Surveillances are credited as an additional follow-on aging management activity. Although the snubbers, themselves, are determined to be active components in the License Renewal Rule, the snubber supports that connect the snubber to the pipe/component and to the structural member are considered passive. Plant Technical Specifications require periodic surveillance of snubbers to ensure functionality. The periodicity is based on past results and is in accordance with a table in the Technical Specifications. Many of the steps of this surveillance address the functionality of the active snubber and are not credited as aging management activities in the context of the License Renewal Rule. However, several steps of the surveillance also address the passive snubber supports. The surveillance requires the following:

- Verification that snubber installation exhibits no signs of detachment from foundation or supporting structures, including clamps, welds, concrete anchor bolts, and general condition of concrete; and
- Verify that the pipe clamp/rod eye bracket is in satisfactory condition and that the snubber is aligned properly.

Any abnormal condition discovered during this surveillance must be reported and resolved in accordance with the site issue reporting and corrective action process. [Reference 2, Pages 1-2, 5-4, and 5-5; and References 38 through 41] The snubber surveillances have been effective in performing visual inspections of snubbers, and changes to the approach to performing these surveillances have not been necessary.

Group 1 - (Piping Supports - General Corrosion of Steel, Loading Due to Hydraulic Vibration or Water Hammer, and Loading Due to Thermal Expansion of Piping/Component) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion of steel, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion of piping/component for piping supports.

- Piping supports associated with piping within the scope of license renewal are themselves considered to be within the scope of license renewal because failure of these supports could lead to failure of the supported component.
- General corrosion, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion were determined to be plausible ARDMs for piping supports. The effects of these ARDMs are loss of support material, reduction of component support strength, loosening of bolted or pinned connections, weld crack initiation and growth, component displacement or misalignment, concrete damage, and hanger setting drift. These effects, if left unmanaged, could lead to loss of the

intended function of the piping supports and ultimately to failure of the supported piping under CLB conditions.

- General corrosion is mitigated by applying coatings to component supports, periodically examining the supports for degradation of that coating or conditions that could accelerate degradation, and by maintaining the coatings.
- Baseline discovery programs include elements that would enable these activities to discover the effect of all plausible aging mechanisms (including degradation of coatings that prevent specific ARDMs) and to determine the appropriate level of follow-on aging management activities.
- Follow-on discovery activities include ISIs, system engineer walkdowns, the control of shift activities, the ownership of plant operating spaces, Snubber Surveillance Inspections, and the ARDI sampling inspections. These activities include elements that would ensure discovery of the effects of all plausible aging mechanisms (including degradation of coatings that prevent specific ARDMs) and require corrective action and actions to prevent recurrence of problem conditions as appropriate. Piping supports within the scope of license renewal are subject to follow-on discovery activities.
- The discovery aging management activities (ISIs, additional baseline walkdowns of selected piping systems, system engineer walkdowns, control of shift activities, ownership of plant operating spaces, snubber surveillances, and the ARDI Program) detect and correct any adverse effects of general corrosion, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed such that the piping supports will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

Group 2 - Cable Raceway Supports, HVAC Ducting Supports, and Equipment Supports: general corrosion of steel

Group 2 includes all 15 component support types within the 3 component support groups: cable raceway supports, HVAC ducting supports, and equipment supports. These type of supports are all subject to age-related degradation due to general corrosion.

Group 2 - (Cable Raceway Supports, HVAC Ducting Supports, and Equipment Supports - General Corrosion of Steel) - Materials and Environment

Cable raceway supports, HVAC ducting supports, and equipment supports are constructed of structural steel and are located inside the Containment Buildings and other climate-controlled buildings (except for some ring foundations for flat-bottom vertical tanks, as described below). Environmental conditions inside the plant for cable raceway supports, HVAC ducting supports, and equipment supports, are identical to those described above, for “Piping Supports.”

Ring foundations for flat-bottom vertical tanks are concrete and are located both inside climate-controlled buildings and outdoors. Environmental conditions for ring foundations inside climate-controlled buildings are identical to those described above, for “Piping Support.” Ring foundations that may be outdoors are subject to changing atmospheric conditions. The site and environment of CCNPP are described in Chapter 2 of the UFSAR.

Group 2 - (Cable Raceway Supports, HVAC Ducting Supports, and Equipment Supports - General Corrosion of Steel) - Aging Mechanism Effects

As shown on Table 3.1-3, general corrosion of steel is an ARDM considered to be plausible for cable raceway supports, HVAC ducting supports and equipment supports (Group 2). General corrosion of steel is plausible for Group 2 supports because humidity levels in the plant could result in moisture coming in contact with the support members. During the plausibility determination, no credit is taken for the protective coating applied to these supports; however, this protective coating plays an important role in the aging management approach for component supports. General corrosion is considered to be plausible for Group 2 supports both inside and outside containment. [Reference 2, Page 2-7 and Reference 2, Page 2-10, Note 1]

The effects of general corrosion on Group 2 supports would be a loss of support material and reduction in component support strength if the ARDM were allowed to progress unmanaged. If these mechanisms were left unmanaged, the effects could progress to the point of insufficient support being afforded to the component and/or allowing excessive motion of the supported component. This failure of the component supports' intended function could, in turn, lead to loss of component intended function under CLB conditions. [Reference 2, Page 2-3]

Group 2 - (Cable Raceway Supports, HVAC Ducting Supports, and Equipment Supports - General Corrosion of Steel) - Methods to Manage Aging Effects

Mitigation

To mitigate the effects of general corrosion, the conditions on the external surfaces of the component support must be controlled. Significant rates of corrosion only occurs when the component support comes in contact with moisture. Preventing direct and prolonged contact between metal surfaces and moisture is an effective mitigation technique for general corrosion. Therefore, to mitigate general corrosion, protective coatings ensure that the external metal surfaces of the component supports are not in contact with a moist, aggressive environment for extended periods of time. In addition, plant housekeeping practices, which identify conditions such as degraded paint, can be used to mitigate the effects of general corrosion. [Reference 2, Page 2-10, Note 1]

Discovery

The effects of general corrosion are detectable by visual techniques. Because the external metal surfaces of the component supports are covered by a protective coating, observing that significant degradation has not occurred to this coating is an effective method to ensure that corrosion has not affected the intended function of the component support. Coatings degrade slowly over time, allowing visual detection during normal operations. Since the coating does not contribute to the intended function of the supports, observing the coating for degradation provides an alert condition, which triggers corrective action prior to the occurrence of degradation that would affect the support's ability to perform its intended function. The degradation of the protective coating or any actual corrosion that does occur can be discovered and corrected by periodically inspecting the supports and by carrying out corrective actions as necessary.

Group 2 - (Cable Raceway Supports, HVAC Ducting Supports, and Equipment Supports - General Corrosion of Steel) - Aging Management Program(s)

Mitigation

The external metal surfaces of the component supports are covered by a protective coating that mitigates the effects of general corrosion. The discovery programs discussed below ensure that the protective coatings of component supports are maintained.

Discovery

For discovery, the level of aging management activity needed for each category of component supports is determined based on the condition observed during a baseline walkdown of a representative sample of supports of each category. Therefore, discovery activities are discussed in two categories, baseline activities and follow-on aging management activities. The as-found condition during the baseline walkdown dictates the level of follow-on aging management needed for the support type. [Reference 2, Pages 6-1 through 6-5]

The Seismic Verification Project (SVP) was established at CCNPP to resolve the NRC's Unresolved Safety Issue A-46 on the seismic adequacy of older nuclear power plants. The SVP used the NRC approved Generic Implementation Procedure (Reference 42) to verify the seismic adequacy of mechanical and electrical equipment required for safe shutdown following a seismic event. The SVP used the SQUG methodology whose acceptance criteria was based on the review of as-found conditions of plant equipment at a large number of industrial facilities worldwide that had experienced strong motion seismic events. [Reference 2, Page 4-1]

A requirement of the SQUG methodology is that walkdown evaluations and inspections be conducted by "Seismic Capability Engineers." These engineers must complete the SQUG developed Walkdown Training Course for Seismic Capability Engineers. The course includes reviews of the Generic Implementation Procedure walkdown evaluation criteria, including criteria for evaluating the condition of equipment anchorages for the variety of anchor types used in the nuclear industry. [Reference 2, Page 4-1]

One area of seismic vulnerability that was found to apply to many types of equipment in the SQUG database was inadequate anchorage. [Reference 2, Page 4-1]. Therefore, the Generic Implementation Procedure methodology emphasizes the inspection of the structural adequacy of the as-found condition of equipment support load paths and anchorages. Generic Implementation Procedure anchorage evaluation requirements include the following actions, performed by the Seismic Capability Engineers. [Reference 2, Page 4-2]

- Documentation of plant inspections on a checklist that was standardized for each generic class of equipment;
- Calculations of the anchorage capacity vs. seismic loading (demand);
- Photographic documentation of equipment anchorages; and
- Evaluation to identify overhead equipment or components with the potential to collapse under a seismic event, consistent with the Class II over I conceptual concern.

Although the majority of the SQUG evaluation methodology is based on visual inspections, there is one part of the anchorage evaluation criteria that requires a "hands-on" inspection. This hands-on inspection applies to concrete expansion anchors, which are used extensively in power plants to anchor equipment such as cabinets, instrument/battery racks, and stanchions. The inspection (called the "anchor tightness check" in Section C.2.3 of the Generic Implementation Procedure) requires applying a small torque to the anchor to confirm the bolt is tight and adequately installed. These checks were performed by CCNPP craft personnel on a sampling of anchor bolts selected by the Seismic Capability Engineers. [Reference 2, Page 4-2]

Because the SVP was a one-time occurrence, baseline activity, its use as an aging management program for component supports is supplemented by the ongoing walkdowns by system engineers and other plant personnel. [Reference 2, Page 4-2]

The combination of the SVP Program and the ongoing walkdowns by system engineers and other plant personnel are deemed adequate to manage the effects of aging in component supports for the following reasons: [Reference 2, Section 4.3]

- The SVP walkdowns, which were credited as baseline inspections for many component support types, were conducted approximately 20 years into the life of both CCNPP units. If there were active ARDMs for a component support, it would be reasonable to assume they would have initiated within the first 20 years of the component support's life. Therefore, the SVP walkdowns can be used to determine whether or not ARDMs are active for a component support. Based on this determination, an appropriate assumption about the future condition of the support can be made, unless plant conditions were to change some time in the future (e.g., degraded coating on a support, pooled water or leaks, irregular humidity for an area). Changes in plant conditions would be identified by the ongoing walkdowns by system engineers and other plant personnel.
- The visual inspections performed by the SVP Program included checks for the following potential ARDMs:
  - ◊ Grout/concrete local deterioration; and
  - ◊ Steel load path and concrete pad degradation potentially caused by loadings from rotating/reciprocating machinery, hydraulic vibration or water hammer, and thermal expansion of piping/component.
- The visual inspections performed by the SVP Program and the system engineer walkdowns include(d) checks for the following additional potential ARDMs:
  - ◊ General corrosion of steel; and
  - ◊ Elastomer hardening.
- The ongoing walkdowns by system engineers and other plant personnel are judged adequate to continue monitoring of the ARDMs listed above on the basis that:
  - ◊ The guidelines for these walkdowns (i.e., PEG-7, NO-1-200, and NO-1-107) require the system engineers and other plant personnel to look for component support condition and other plant conditions that could potentially affect the component supports;

◊ The system engineers and other plant personnel are required to document deficiencies in accordance with QL-2-100;

◊ System engineers and other plant personnel occasionally find component support deficiencies like those that would occur due to aging, which indicates that component support aging is being managed; and

◊ Additionally, because CCNPP commits to SQUG methodology as an alternative method for the verification of the seismic adequacy of new and replacement equipment, Seismic Capability Engineers will be available to assist the system engineers, as required, in evaluating cases of questionable support condition.

Baseline Walkdowns

The aging management approach for cable raceway supports, HVAC ducting supports, and equipment supports relies on baseline walkdown activities. The activities for these supports include one or more of the following:

- Inspections performed by the SVP;
- Inspections performed by the ISI Program;
- Additional sampling baseline walkdowns; or
- Determination that walkdowns performed on similar types of supports in similar environments were sufficient such that no baseline walkdowns were required (e.g., for HVAC ducting supports outside containment, credit was taken for the SVP inspections of cable raceway supports outside containment).

For component supports subject to baseline inspection under the SVP, the inspections were conducted in accordance with the criteria stated above. These completed SVP inspections serve as an adequate baseline activity to document the condition of component supports and the results of the SVP inspections are maintained at CCNPP. [Reference 2, Page 6-5] The component supports inspected by the SVP included the supports for the mechanical and electrical equipment on the CCNPP Safe Shutdown Equipment List, and included the following types of supports: [Reference 2, Table 3-1]

- Trapeze, cantilever, and other cable raceway support styles (outside and inside containment);
- Elastomer vibration isolators outside containment;
- Electrical cabinet anchorage outside containment;
- Equipment frames and stanchions for instruments and batteries outside containment;
- Equipment frames and stanchions for instruments inside containment;
- Frames and saddles for tanks and heat exchangers (outside and inside containment);
- Metal spring isolators and fixed bases (outside and inside containment); and
- Ring foundations for flat-bottom vertical tanks.

For these component support types, no active general corrosion was discovered except on certain electrical cabinet anchorages outside containment. Corrosion was found on the cabinet anchorage for sampling system hoods, and additional walkdowns will be conducted to determine the condition of the anchorage of similar cabinets. For all other component support types subject to SVP inspection, no additional action for general corrosion is required and the follow-on activities discussed below are adequate for continued aging management. [Reference 2, Pages 6-7 through 6-12]

For component supports subject to baseline inspection under the ISI Program, the inspections were conducted in accordance with the criteria stated above in the subsection, Group 1 - Aging Management Programs. These completed ISIs serve as an adequate baseline activity to document the condition of component supports, and the results of the ISIs are maintained at CCNPP. [Reference 2, Page 6-5] The component support types subject to inspection under the ISI Program are equipment supports (frames and saddles for tanks and heat exchangers outside containment, frames and saddles for tanks and heat exchangers inside containment, and LOCA restraints). [Reference 2, Pages 6-7 through 6-12]

For component supports that were not covered or only partially covered by the SVP or the ISI Program, and environmental or other differences prevented extrapolation of results to cover these component supports, additional sampling walkdowns are needed. The walkdown scope will include inspection, on a sampling basis, for corrosion, and will be documented using means such as field notes and photographs. These walkdowns will document the condition of the component supports within the scope of license renewal. Once these additional walkdowns are completed, an adequate baseline condition assessment will have been completed. [Reference 2, Page 6-4, Table 6-1] The component support types subject to additional sampling walkdowns are rod hanger trapeze supports for HVAC ducting inside containment; electrical cabinet anchorage outside containment (anchorage for sampling system hoods only), and electrical cabinet anchorage inside containment (for six radiation monitors). [Reference 2, Table 6-1]

Follow-on Activities

Because the SVP was a one-time occurrence, the commodity approach for component supports also relies on the ongoing site activities for managing aging of component supports. [Reference 2, Page 1-2]

For component supports covered by the SVP, the follow-on activities for aging management of these component supports will be system engineer walkdowns, the Control of Shift Activities Program, and the Ownership of Plant Operating Spaces Program. [Reference 2, Section 4.2] The purpose, scope, bases, etc., for these programs are described above in the subsection, Group 1 - Aging Management Programs. Although the containment air cooler fans (metal spring isolators and fixed bases inside containment) received an adequate baseline inspection as part of the SVP and no aging was discovered, these supports are not accessible for system engineer walkdowns since the spring isolator supports are located internal to the fan. Therefore, the preventive maintenance checklists (MPM 09150 and MPM 09151), which open and inspect other components internal to the fan housing, will be modified to also inspect these spring isolator supports for signs of general corrosion. [Reference 2, Page 6-12]

Based on the results of baseline inspections completed per the existing ISI Program requirements, it was determined that continuing ASME Section XI ISIs into the period of extended operations will also serve as an adequate follow-on activity for those component supports subject to that program. [Reference 2, Page 5-4] The purpose, scope, bases, etc., for the ISI Program are described above in the subsection, Group 1 - Aging Management Programs.

For those component supports that require additional baseline walkdowns, the results of those walkdowns will determine the extent of aging management practices needed for these supports. If the baseline walkdowns reveal no significant effects of aging from general corrosion, then the follow-on activities for aging management of these component supports will be system engineer walkdowns, the Control of Shift Activities Program, and the Ownership of Plant Operating Spaces Program. [Reference 2, Page 5-4; and Reference 2, Page 4-2]

Group 2 - (Cable Raceway Supports, HVAC Ducting Supports, and Equipment Supports - General Corrosion of Steel) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion of steel for cable raceway supports, HVAC ducting supports, and equipment supports.

- Group 2 supports associated with components within the scope of license renewal are themselves considered to be within the scope of license renewal because failure of these supports could lead to failure of the supported plant component.
- General corrosion was determined to be a plausible ARDM for Group 2 supports. The effects of the ARDM are a loss of support material and reduction of component support strength. These effects, if left unmanaged, could lead to loss of the intended function of the component supports and ultimately to failure of the supported plant component under CLB conditions.
- General corrosion is mitigated by applying coatings to component supports, periodically examining the supports for degradation of that coating or conditions that could accelerate degradation, and by maintaining the coatings.
- Baseline discovery programs include elements that would enable these activities to discover the effect of all plausible aging mechanisms (including degradation of coatings that prevent specific ARDMs) and to determine the appropriate level of follow-on aging management activities.
- Follow-on discovery activities include ISIs, system engineer walkdowns, the control of shift activities, the ownership of plant operating spaces, and preventive maintenance checklists (for containment air cooler fans). These activities include elements that would ensure discovery of the effects of all plausible aging mechanisms (including degradation of coatings that prevent specific ARDMs) and require corrective action and actions to prevent recurrence of problem conditions, as appropriate. Group 2 supports within the scope of license renewal are subject to follow-on discovery activities.
- The discovery aging management activities (ISIs, SVP inspections, additional baseline walkdowns, system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces) detect and correct any adverse effects of general corrosion.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed such that the cable raceway supports, HVAC ducting supports, and equipment support types will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

Group 3 - Elastomer Vibration Isolators: Elastomer Hardening

Vibrations resulting from rotating equipment or other sources are, in general, transmitted to the surrounding structure. Elastomer materials are used in the anchorage load path of some rotating equipment to reduce the vibration transmitted to the supporting structures. Group 3 includes elastomer vibration isolators for equipment such as fans and compressors. In addition to general corrosion discussed in Group 2, these type of supports are subject to age-related degradation due to hardening of the elastomer material.

Group 3 - (Elastomer Vibration Isolators - Elastomer Hardening) - Materials and Environment

Elastomer is the generic term used to describe a variety of natural and synthetic rubber products. Elastomer substantially recovers its original shape and size after removal of a deforming force. [Reference 43, Page 16]

Environmental conditions for Group 3 component supports inside the plant are identical to those described above, for "Piping Supports." However, some Group 3 supports may be subject to temperature conditions higher than ambient conditions due to their close proximity to heat generating equipment.

Group 3 - (Elastomer Vibration Isolators - Elastomer Hardening) - Aging Mechanism Effects

As shown on Table 3.1-3, elastomer hardening is an ARDM considered to be plausible for elastomer vibration isolators (Group 3). [Reference 2, Pages 2-7 and 2-8]

Extended exposure to light, heat, oxygen, ozone, water, or radiation can cause scission or cross linking of the polymer chains forming the elastomer material. Chain scission (the breaking of chemical bonds) lowers the elastomer tensile strength and elastic modulus. Cross linking (undesirable linking of adjacent polymer strings at susceptible sites) causes the elastomer to become more brittle and promotes surface cracking, which may lead to loss of strength and subsequent failure. [Reference 2, Section 2.2.3] Elastomers used to dampen vibration are subject to age hardening, even in mild environments [Reference 2, Table 2-1, Note 11].

This aging mechanism, if unmanaged, could eventually lead to loss of the elastomer vibration dampening function. Loss of this function could, in turn, lead to a loss of function of the supported equipment under CLB conditions. Therefore, elastomer hardening was determined to be a plausible ARDM for which the aging effects must be managed for elastomer vibration isolators.

Group 3 - (Elastomer Vibration Isolators - Elastomer Hardening) - Methods to Manage Aging Effects

Mitigation

Since elastomer hardening is affected by exposure to environmental conditions that are not feasible to control (e.g., light, heat, oxygen, ozone, water, radiation), there are no practical methods to mitigate its effects.

Discovery

The effects of elastomer hardening for elastomer vibration isolators are detectable by visual inspection techniques. Therefore, adequate discovery techniques to detect the effects of aging must include a visual observation of the external condition of the elastomer material on elastomer vibration isolators. [Reference 2, Page 6-8]

Group 3 - (Elastomer Vibration Isolators - Elastomer Hardening) - Aging Management Program(s)

Mitigation

There are no CCNPP programs credited for mitigation of elastomer hardening.

Discovery

For discovery, the level of aging management activity needed for each category of component supports is determined based on the condition observed during a baseline walkdown of a representative sample of supports of each category. Therefore, discovery activities are discussed in two categories, baseline activities and follow-on aging management activities. The as-found condition during the baseline walkdown dictates the level of follow-on aging management needed for the support type. [Reference 2, Pages 6-1 through 6-5]

Baseline Walkdowns

Some elastomer vibration isolators were subject to sampling baseline walkdown activities under the SVP.

Completed SVP inspections serve as an adequate baseline activity to document the condition of component supports and the results of the SVP inspections are maintained at CCNPP. [Reference 2, Page 6-5] The purpose, scope, bases, etc., for the SVP are described above in the subsection, Group 2 - Aging Management Programs. The SVP found the current condition of vibration isolators inspected to be acceptable, except for those that support the Control Room HVAC air handler. Prior to the SVP walkdown, these supports had been identified by the system engineer as requiring replacement, and a modification had been planned to replace the elastomer isolators with spring-type isolators. After these isolators are replaced, the follow-on activities described below are judged to be adequate to manage aging of elastomer vibration isolator component supports for other equipment. [Reference 2, Page 6-8]

Follow-on Activities

Because the SVP was a one-time occurrence, the commodity approach for component supports also relies on the ongoing site activities for managing aging of component supports. [Reference 2, Page 1-2]

The follow-on activities for aging management of the elastomer vibration isolator component supports will be system engineer walkdowns, the Control of Shift Activities Program, and the Ownership of Plant Operating Spaces Program. The purpose, scope, bases, etc., for these programs are described above in the subsection, Group 1 - Aging Management Programs.

The system engineer walkdown inspection technique with respect to elastomer vibration isolators has typically included pushing on the isolator to assess its pliability and a visual inspection to detect signs of cracking. This technique has been shown in the past to be effective in identifying elastomer hardening prior to loss of the CLB function.

Group 3 - (Elastomer Vibration Isolators - Elastomer Hardening) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to elastomer hardening for elastomer vibration isolators.

- Group 3 supports associated with components in the scope of license renewal are themselves considered to be within the scope of license renewal because failure of these supports could lead to failure of the supported plant component.
- Elastomer hardening was determined to be a plausible ARDM for Group 3 supports. This aging mechanism, if unmanaged, could eventually lead to loss of the elastomer vibration dampening function. Loss of this function could, in turn, lead to a loss of function of the supported equipment under CLB conditions. A modification had been planned, for the Control Room HVAC air handler supports, to replace the elastomer isolators with spring-type isolators.
- Baseline discovery programs include elements that would enable these activities to discover the effect of all plausible aging mechanisms, and to determine the appropriate level of follow-on aging management activities.
- Follow-on discovery activities include system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces for elastomer vibration isolators. These activities include elements that would ensure discovery of the effects of all plausible aging mechanisms and require corrective action and actions to prevent recurrence of problem conditions, as appropriate. Group 3 elastomer vibration isolators within the scope of license renewal, are subject to follow-on discovery activities.
- The discovery aging management activities (SVP inspections, system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces) detect and correct any adverse effects of elastomer hardening for elastomer vibration isolators.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed such that the elastomer vibration isolators will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

Group 4 - Metal Spring Isolators and Fixed Bases (outside containment) / LOCA Restraints: Loading Due to Rotating/Reciprocating Equipment

Group 4 includes metal spring isolators and fixed bases for rotating/reciprocating equipment, such as pumps and fans. Group 4 also includes LOCA restraints for the reactor coolant pumps. In addition to general corrosion discussed in Group 2, these type of supports are subject to age-related degradation due to vibration transmitted from the rotating/reciprocating equipment.

Group 4 - (Metal Spring Isolators and Fixed Bases (outside containment) / LOCA Restraints - Loading Due to Rotating/Reciprocating Machinery) - Materials and Environment

Metal spring isolators and LOCA restraints are constructed of structural steel. Metal spring isolators and fixed bases subject to loading due to rotating/reciprocating machinery are located outside of the Containment Buildings. Loss-of-coolant accident restraints subject to loading due to rotating/reciprocating machinery are located inside the Containment Buildings. Environmental conditions for metal spring isolators and LOCA restraints are identical to those described above, for "Piping Supports." [Reference 2, Page 6-12]

Group 4 - (Metal Spring Isolators and Fixed Bases (outside containment) / LOCA Restraints - Loading Due to Rotating/Reciprocating Machinery) - Aging Mechanism Effects

As shown in Table 3.1-3, loading due to rotating/reciprocating machinery is the ARDM considered to be plausible for metal spring isolators, fixed bases, and LOCA restraints (Group 4) that are anchored to concrete. [Reference 2, Pages 2-9; and 2-10, Note 8]

Loading due to rotating/reciprocating machinery is plausible for supports in Group 4 because the machinery supported by these metal spring isolators, fixed bases, and LOCA restraints is subject to vibration from rotation and/or reciprocation while in operation.

The effects of loading due to rotating/reciprocating machinery are steel load path degradation, concrete pad degradation, and concrete cracking in the vicinity of the equipment anchorage, and consequently a reduction in component support strength if the ARDM were allowed to progress unmanaged. If these mechanisms were left unmanaged, the effects could progress to the point of reducing the amount of support afforded to the component and/or allowing excessive motion of the supported component. This failure of the component supports' intended function could, in turn, lead to loss of function of the supported equipment under CLB conditions. [Reference 2, Pages 2-10 and 4-4]

For the metal spring isolators, fatigue cracking of the springs is not considered plausible. Springs are designed for infinite cycles of design loadings, and unless improperly designed, would fail only during an overload (i.e., non-design) condition. Therefore, the ARDM "loading due to rotating/reciprocating machinery," focuses on other signs of degradation, e.g., cracking of adjacent concrete.

Group 4 - (Metal Spring Isolators and Fixed Bases (outside containment) / LOCA Restraints - Loading Due to Rotating/Reciprocating Machinery) - Methods to Manage Aging Effects

Mitigation

The effects of the ARDM loading due to rotating/reciprocating machinery for component supports have been minimized through proper support design and through proper system operation. Therefore, no additional specific measures to mitigate this ARDM are needed.

Discovery

Methods to discover the effects of loading due to rotating/reciprocating machinery are a visual observation of the support and/or the surrounding concrete. [Reference 2, Pages 4-4 and 6-12]

Group 4 - (Metal Spring Isolators and Fixed Bases (outside containment) / LOCA Restraints - Loading Due to Rotating/Reciprocating Machinery) - Aging Management Program(s)

Mitigation

There are no CCNPP programs credited for mitigation of loading due to rotating/reciprocating machinery.

Discovery

For discovery the level of aging management activity needed for each category of component supports is determined based on the condition observed during a baseline walkdown of a representative sample of supports of each category. Therefore, discovery activities are discussed in two categories, baseline activities and follow-on aging management activities. The as-found condition during the baseline walkdown dictates the level of follow-on aging management needed for the support type. [Reference 2, Pages 6-1 through 6-5]

Baseline Walkdowns

Some metal spring isolators and fixed bases outside containment were subject to baseline inspection under the SVP. These completed SVP inspections serve as an adequate baseline activity to document the condition of component supports, and the results of the SVP inspections are maintained at CCNPP. [Reference 2, Page 6-5] The results of the SVP baseline did not identify any active ARDMs for metal spring isolators and fixed bases. Therefore, the follow-on activities described below are adequate for continued aging management. [Reference 2, Page 6-12] The purpose, scope, bases, etc., for the SVP are described above in the subsection, Group 2 - Aging Management Programs.

Loss-of-coolant accident restraints are subject to baseline inspection under the ISI Program. These completed ISIs serve as an adequate baseline activity to document the condition of component supports, and the results of the ISIs are maintained at CCNPP. [Reference 2, Pages 6-5 and 6-12] The purpose, scope, bases, etc., for the ISI are described above in the subsection, Group 1 - Aging Management Programs.

Follow-on Activities

Because the SVP was a one-time occurrence, the commodity approach for component supports also relies on the ongoing site activities for managing aging of component supports that were baselined under the SVP. [Reference 2, Page 1-2]

The follow-on activities for aging management of the metal spring isolators and fixed bases component supports will be system engineer walkdowns, the Control of Shift Activities Program, and the Ownership of Plant Operating Spaces Program. [Reference 2, Pages 4-2 and 6-12] The purpose, scope, bases, etc., for these programs are described above in the subsection, Group 1 - Aging Management Programs.

Based on the results of baseline inspections completed per the existing ISI Program requirements, it was determined that continuing ASME Section XI ISIs into the period of extended operation will also serve as an adequate follow-on activity for LOCA restraints subject to that program. [Reference 2, Page 5-4]

Group 4 - (Metal Spring Isolators and Fixed Bases (outside containment) / LOCA Restraints - Loading Due to Rotating/Reciprocating Machinery) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to loading due to rotating/reciprocating machinery for metal spring isolators and fixed bases/LOCA restraints.

- Group 4 supports associated with components in the scope of license renewal are themselves considered to be within the scope of license renewal because failure of these supports could lead to failure of the supported plant component.
- Loading due to rotating/reciprocating machinery was determined to be a plausible ARDM for Group 4 supports. The effects of the ARDM are steel load path degradation, concrete pad degradation, and concrete cracking in the vicinity of the equipment anchorage and subsequent loss of strength of the component support. These effects, if left unmanaged, could lead to loss of the intended function of the component supports and ultimately to failure of the supported component under CLB conditions.
- Baseline discovery programs include elements that would enable these activities to discover the effect of this plausible aging mechanism and to determine the appropriate level of follow-on aging management activities.
- Follow-on discovery activities include ISIs, system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces. These activities include elements that would ensure discovery of the effects of this plausible aging mechanism and require corrective action and actions to prevent recurrence of problem conditions, as appropriate. Group 4 supports within the scope of license renewal are subject to follow-on discovery activities.
- The discovery aging management activities (ISIs, SVP inspections, system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces) detect and correct any adverse effects of loading due to rotating/reciprocating equipment.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed such that the metal spring isolators, fixed bases, and LOCA restraints will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

Group 5 - Frames and Saddles / LOCA Restraints: Loading due to Hydraulic Vibration or Water Hammer

Group 5 includes frames and saddles for tanks and heat exchangers. Group 5 also includes LOCA restraints for the pressurizer and the reactor coolant pumps. In addition to general corrosion discussed in Group 2, these type of supports are subject to age-related degradation due to hydraulic loadings (e.g., flow-induced vibration, flashing flow, or steam bubble collapse). [Reference 2, Pages 2-5, 6-11, and 6-12, Table 2-1]

Group 5 - (Frames and Saddles / LOCA Restraints - Loading due to Hydraulic Vibration or Water Hammer) - Materials and Environment

Frames and saddles are constructed of structural steel. Frames and saddles are located inside the Containment Buildings and inside other climate-controlled buildings. Environmental conditions for frames and saddles are identical to those described above, for "Piping Supports." [Reference 2, Page 6-11]

Loss-of-coolant accident restraints are constructed of structural steel and are only located inside the Containment Buildings. Environmental conditions for LOCA restraints are identical to those described above, for "Piping Supports." [Reference 2, Page 6-12]

Group 5 - (Frames and Saddles / LOCA Restraints - Loading due to Hydraulic Vibration or Water Hammer) - Aging Mechanism Effects

As shown in Table 3.1-3, loading due to hydraulic vibration or water hammer is considered to be plausible for frames, saddles, and LOCA restraints. [Reference 2, Pages 2-8 and 2-9]

Loading due to hydraulic vibration or water hammer is plausible for supports in Group 5 because the plant equipment supported by these equipment supports could be subject to hydraulic vibration or water hammer during plant operation.

The aging effects due to this ARDM would be loosening of bolted connections, loss of weld integrity, and component displacement or misalignment. If this aging mechanism were left unmanaged, the effects could progress to the point of insufficient support afforded to the components and/or allowing excessive movement of the equipment or component. This failure of the equipment supports' intended function could, in turn, lead to failure of the supported equipment under CLB conditions. [Reference 2, Page 5-4]

Group 5 - (Frames and Saddles / LOCA Restraints - Loading due to Hydraulic Vibration or Water Hammer) - Methods to Manage Aging Effects

Mitigation

The effects of the ARDM loading due to hydraulic vibration or water hammer for component supports have been minimized through proper support design and through proper system operation. Loading due to hydraulic vibration or water hammer is only a concern due to the potential for off-normal operation and transients. Therefore, no additional specific measures to mitigate this ARDM are needed.

Discovery

The effects of loading due to hydraulic vibration or water hammer are detectable by visual observation of external conditions. The effects of excessive loading from hydraulic vibration or water hammer are observable initially in the form of loosening of bolted connections, loss of weld integrity, and component displacement or misalignment. These conditions would be readily observable during a visual inspection. [Reference 2, Page 5-4]

Group 5 - (Frames and Saddles / LOCA Restraints - Loading due to Hydraulic Vibration or Water Hammer) - Aging Management Program(s)

Mitigation

There are no CCNPP programs credited for mitigation of loading due to hydraulic vibration or water hammer.

Discovery

For discovery, the level of aging management activity needed for each category of component supports is determined based on the condition observed during a baseline walkdown of a representative sample of supports of each category. Therefore, discovery activities are discussed in two categories, baseline activities and follow-on aging management activities. The as-found condition during the baseline walkdown dictates the level of follow-on aging management needed for the support type. [Reference 2, Pages 6-1 through 6-5]

Baseline Walkdowns

Several programs are credited with discovery methods for identifying degradation from loading due to hydraulic vibration or water hammer. Frames, saddles, and LOCA restraints are included within the scope of the SVP and the ISI Program sampling baseline walkdowns. [Reference 2, Tables 3-1 and 6-1] (Note that supports for the spent fuel pool cooling demineralizer and ion exchanger vessels are addressed in the AMR for that system and are not covered by this commodity evaluation.)

Some frames and saddles were subject to baseline inspection under the SVP. Completed SVP inspections serve as an adequate baseline activity to document the condition of frames and saddles, and the results of the SVP inspections are maintained at CCNPP. [Reference 2, Page 6-5] The results of the SVP baseline did not identify any active ARDMs for the component supports inspected, and the follow-on activities discussed below are adequate for continued aging management. [Reference 2, Page 6-11] The purpose, scope, bases, etc., for the SVP are described above in the subsection, Group 2 - Aging Management Programs.

Frames and saddles are also subject to baseline inspection under the ISI Program. These completed ISIs serve as an adequate baseline activity to document the condition of component supports, and the results of the ISIs are maintained at CCNPP. [Reference 2, Pages 6-11 and 5-4] The purpose, scope, bases, etc., for the ISI are described above in the subsection, Group 1 - Aging Management Programs.

Loss-of-coolant accident restraints are subject to baseline inspection under the ISI Program. These completed ISIs serve as an adequate baseline activity to document the condition of component supports, and the results of the ISIs are maintained at CCNPP. [Reference 2, Page 6-12] The purpose, scope, bases, etc., for the ISI are described above in the subsection, Group 1 - Aging Management Programs.

The results of the SVP baseline and the continual ISIs concluded that no additional actions, other than follow-on activities discussed below, are needed. [Reference 2, Page 6-11]

Follow-on Activities

Since the SVP was a one-time occurrence, the commodity approach for component supports also relies on the ongoing site activities for managing aging of component supports. [Reference 2, Page 1-2]

The follow-on activities for aging management of the frames and saddles component supports will be system engineer walkdowns, the Control of Shift Activities Program, and the Ownership of Plant Operating Spaces Program. [Reference 2, Pages 4-2 and 6-11] The purpose, scope, bases, etc., for these programs are described above in the subsection, Group 1 - Aging Management Programs.

Based on the results of baseline inspections completed per the existing ISI Program requirements, it was determined that continuing ASME Section XI ISIs into the period of extended operation will also serve as an adequate follow-on activity for frames, saddles, and LOCA restraints subject to that program. [Reference 2, Page 5-4]

Group 5 - (Frames and Saddles / LOCA Restraints - Loading due to Hydraulic Vibration or Water Hammer) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to loading due to hydraulic vibration or water hammer for frames, saddles, and LOCA restraints.

- Group 5 supports associated with components in the scope of license renewal are themselves considered to be within the scope of license renewal because failure of these supports could lead to failure of the supported plant component.
- Loading due to hydraulic vibration or water hammer was determined to be a plausible ARDM for Group 5 supports. The effects of the ARDM are loosening of bolted connections, loss of weld integrity, and component displacement or misalignment that lead to loss of structural adequacy and subsequent loss of strength of the component support. This effect, if left unmanaged, could lead to loss of the intended function of the component supports and ultimately to failure of the supported plant component under CLB conditions.
- Baseline discovery programs include elements that would enable these activities to discover the effect of this plausible aging mechanism and to determine the appropriate level of follow-on aging management activities.
- Follow-on discovery activities include ISIs, system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces. These activities include elements that would ensure discovery of the effects of this plausible aging mechanism and require corrective action and actions to prevent recurrence of problem conditions as appropriate. Group 5 supports within the scope of license renewal are subject to follow-on discovery activities.
- The discovery aging management activities (ISIs, SVP inspections, system engineer walkdowns, the control of shift activities, the ownership of plant operating spaces) detect and correct any adverse effects of loading due to hydraulic vibration or water hammer.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed such that the frames, saddles, and LOCA restraints will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

Group 6 - Frames and Saddles / Ring Foundation for Flat-Bottom Vertical Tanks: Loading Due to Thermal Expansion

Group 6 includes frames and saddles that are located inside and outside of the Containment Buildings, for equipment such as tanks and heat exchangers. Group 6 also includes ring foundations for flat-bottom vertical tanks. In addition to general corrosion discussed in Group 2, these type of supports are subject to age-related degradation due to thermal expansion of piping or components.

Group 6 - (Frames and Saddles / Ring Foundation for Flat-Bottom Vertical Tanks - Loading Due to Thermal Expansion) - Materials and Environment

Frames and saddles are constructed of structural steel. Frames and saddles are located inside the Containment Buildings and inside other climate-controlled buildings. Environmental conditions for frames and saddles are identical to those described above, for "Piping Supports." [Reference 2, Page 2-8]

Ring foundations for flat-bottom vertical tanks are concrete and are located both inside climate-controlled buildings and outdoors. Environmental conditions for ring foundations inside climate-controlled buildings are identical to those described above, for "Piping Supports." Ring foundations that may be outdoors are subject to changing atmospheric conditions. The site and environment of CCNPP are described in Chapter 2 of the UFSAR. [Reference 2, Page 2-11, Note 19, Page 6-12]

Group 6 - (Frames and Saddles / Ring Foundation for Flat-Bottom Vertical Tanks - Loading Due to Thermal Expansion) - Aging Mechanism Effects

As shown in Table 3.1-3, loading due to thermal expansion is considered to be plausible for frames, saddles, and ring foundations. Loading due to thermal expansion is plausible for supports in Group 6 because these types of equipment supports are subject to thermal cycling while performing their intended functions. The concrete ring foundations of large, flat-bottom vertical tanks are subject to thermal cycling, especially during periods of cold weather when tank contents are heated with flow from warm sources, e.g., the main condenser. [Reference 2, Pages 2-8, 2-9, and 2-11]

The aging effects due to this ARDM would be loosening of bolted connections, loss of weld integrity, component displacement or misalignment, and cracking of concrete. If this aging mechanism were left unmanaged, the effects could progress to the point of reducing the amount of support afforded to the components and/or allowing excessive movement of the equipment or component. This failure of the equipment supports' intended function could, in turn, lead to failure of the supported equipment under CLB conditions. [Reference 2, Pages 5-4 and 6-12]

Group 6 - (Frames and Saddles / Ring Foundation for Flat-Bottom Vertical Tanks - Loading Due to Thermal Expansion) - Methods to Manage Aging Effects

Mitigation

The effects of the ARDM loading due to thermal expansion for component supports have been minimized through proper support design and through proper system operation. Therefore, no additional specific measures to mitigate this ARDM are needed.

Discovery

The effects of loading due to thermal expansion are detectable by visual observation of external conditions. The effects of excessive loading from thermal expansion are observable initially in the form of loosening of bolted connections, weld crack initiation and growth, component displacement or misalignment, and cracking of concrete. These conditions would be readily observable during a visual inspection. [Reference 2, Pages 5-4, 6-11, and 6-12]

Group 6 - (Frames and Saddles / Ring Foundation for Flat-Bottom Vertical Tanks - Loading Due to Thermal Expansion) - Aging Management Program(s)

Mitigation

There are no CCNPP programs credited for mitigation of loading due to thermal expansion.

Discovery

For discovery, the level of aging management activity needed for each category of component supports is determined based on the condition observed during a baseline walkdown of a representative sample of supports of each category. Therefore, discovery activities are discussed in two categories, baseline activities and follow-on aging management activities. The as-found condition during the baseline walkdown dictates the level of follow-on aging management needed for the support type. [Reference 2, Pages 6-1 through 6-5]

Baseline Walkdowns

Several programs are credited with discovery methods for identifying degradation from loading due to thermal expansion. Frames, saddles, and ring foundations for flat-bottom vertical tanks are included within the scope of the SVP and the ISI Program sampling baseline walkdowns. [Reference 2, Pages 3-14 and 6-11]

Some frames, saddles, and ring foundations were subject to baseline inspection under the SVP. Completed SVP inspections serve as an adequate baseline activity to document the condition of frames, saddles, and ring foundations, and the results of the SVP inspections are maintained at CCNPP. [Reference 2, Page 6-5] The results of the SVP baseline did not identify any active ARDMs for the frames and saddles inspected, and the follow-on activities are adequate for continued aging management. The SVP baseline for ring foundations found radial cracks in the concrete rings for some of the tanks that were inspected, but the impact of these cracks on the structural adequacy of the anchorage was judged to be insignificant in the SVP evaluations. Follow-on activities are adequate for continued aging management for the ring foundations. [Reference 2, Pages 6-11 and 6-12] The purpose, scope, bases, etc., for the SVP are described above in the subsection, Group 2 - Aging Management Programs.

Frames and saddles are also subject to baseline inspection under the ISI Program. These completed ISIs serve as an adequate baseline activity to document the condition of component supports, and the results of the ISIs are maintained at CCNPP. [Reference 2, Pages 5-4 and 6-11] The purpose, scope, bases, etc., for the ISI are described above in the subsection, Group 1 - Aging Management Programs.

The results of the SVP baseline and the continual ISIs concluded that no additional actions, other than follow-on activities discussed below, are needed. [Reference 2, Pages 6-11 and 6-12]

Follow-on Activities

Because the SVP was a one-time occurrence, the commodity approach for component supports also relies on the ongoing site activities for managing aging of component supports. [Reference 2, Page 1-2]

The follow-on activities for aging management of the frames, saddles, and ring foundation component supports will be system engineer walkdowns, the Control of Shift Activities Program, and the Ownership of Plant Operating Spaces Program. [Reference 2, Page 4-2] The purpose, scope, bases, etc., for these programs are described above in the subsection, Group 1 - Aging Management Programs.

Based on the results of baseline inspections completed per the existing ISI Program requirements, it was determined that continuing ASME Section XI ISIs into the period of extended operation will also serve as an adequate follow-on activity for frames and saddles subject to that program. [Reference 2, Page 5-4]

Group 6 - (Frames and Saddles / Ring Foundation for Flat-Bottom Vertical Tanks - Loading Due to Thermal Expansion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to loading due to thermal expansion for frames, saddles, and ring foundations.

- Group 6 supports associated with components in the scope of license renewal are themselves considered to be within the scope of license renewal because failure of these supports could lead to failure of the supported plant component.
- Loading due to thermal expansion was determined to be a plausible ARDM for Group 6 supports. The effects of the ARDM are loosening of bolted connections, weld crack initiation and growth, component displacement or misalignment, and cracking of concrete that lead to loss of structural adequacy and subsequent loss of strength of the component support. This effect, if left unmanaged, could lead to loss of the intended function of the component supports and ultimately to failure of the supported plant component under CLB conditions.
- Baseline discovery programs include elements that would enable these activities to discover the effect of this plausible aging mechanism and to determine the appropriate level of follow-on aging management activities.
- Follow-on discovery activities include ISIs, system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces. These activities include elements that would ensure discovery of the effects of this plausible aging mechanism and require corrective action and actions to prevent recurrence of problem conditions, as appropriate. Group 6 supports within the scope of license renewal are subject to follow-on discovery activities.
- The discovery aging management activities (ISIs, SVP inspections, system engineer walkdowns, the control of shift activities, and the ownership of plant operating spaces) detect and correct any adverse effects of loading due thermal expansion.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed such that the frames, saddles, and ring foundations will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

Group 7 - Frames and Saddles (inside containment) / LOCA Restraints: Stress Corrosion Cracking of High Strength Bolts

Group 7 includes frames and saddles for safety injection tanks and LOCA restraints for the pressurizer. In addition to general corrosion discussed in Group 2, these type of supports are subject to age-related degradation of anchor bolting due to stress corrosion cracking because of the bolting material in use for these supports. [Reference 2, Pages 2-4; 2-9; 2-10, Note 2; Pages 6-11 and 6-12]

Group 7 - (Frames and Saddles (inside containment) / LOCA Restraints - Stress Corrosion Cracking of High Strength Bolts) - Materials and Environment

Frames, saddles, and LOCA restraints are constructed of structural steel with anchor bolting of various grades of steel as specified for the particular design. Frames, saddles, and LOCA restraints for a limited number of tanks, vessels, and heat exchangers contain relatively high strength anchor bolting and are, therefore, subject to stress corrosion cracking. These supports are located inside the Containment Building. Environmental conditions for frames, saddles, and LOCA restraints are identical to those described above, for "Piping Supports." [Reference 2, Pages 6-11 and 6-12]

Group 7 - (Frames and Saddles (inside containment) / LOCA Restraints - Stress Corrosion Cracking of High Strength Bolts) - Aging Mechanism Effects

Industry experience has shown that high strength bolting (i.e., those with yield strength greater than 150 ksi) installed in some Nuclear Steam Supply System applications could be subject to stress corrosion cracking in a humid environment. The only two types of high strength bolting that can be found in anchor bolt applications at CCNPP are A354 and A490. Specifically, A354 bolting was used in the reactor vessel, pressurizer, and safety injection tank anchor bolts; and A490 bolting was used in the steam generator supports. (Note that reactor vessel and steam generator supports were not included in the Component Supports Commodity Evaluation.) Therefore, stress corrosion cracking is only plausible for pressurizer and safety injection tank support bolting since these supports are the only applications with high strength bolting in the scope of this commodity evaluation. [Reference 2, Pages 2-4 and 2-10]

Per UFSAR Section 5.1.2.3, pressurizer and safety injection tank support bolting is type A354 Grade BC. Per EPRI report NP-5769 Table 4-1, this type of bolting has failed in similar applications in nuclear power plants due to stress corrosion cracking. However, these failures occurred due to improper heat treatment of the bolting during manufacture, or improper material supplied for this specification. Therefore, it is unlikely that stress corrosion cracking will affect these bolts installed at CCNPP. Additionally, if any such bolting were installed in improper applications, it would have failed due to stress corrosion cracking soon after installation rather than after many years. These failures would have been detected by routine and programmatic inspections, e.g., NRC IE Bulletins 79-02 and 79-14, and ISI. However, due to the industry experience documented in the above referenced EPRI report, stress corrosion cracking is considered to be plausible for pressurizer support bolting and safety injection tank support bolting only. [Reference 2, Pages 2-4, 3-16; and Reference 2, Page 2-10, Notes 2, 6]

As shown in Table 3.1-3, stress corrosion cracking of high strength bolts is considered to be plausible for frames, saddles inside containment, and LOCA restraints. [Reference 2, Page 2-9] The pressurizer support bolting is categorized under LOCA restraints, and the safety injection tank support bolting is categorized under frames and saddles inside containment.

The resultant aging effects would be cracking and failure of bolt material. If this aging mechanism were left unmanaged, the effects could progress to the point of insufficient support afforded to the components and/or allowing excessive movement of the components. This failure of the component supports' intended function could, in turn, lead to failure of supported component function under CLB conditions. [Reference 2, Pages 5-4 and 6-11]

Group 7 - (Frames and Saddles (inside containment) / LOCA Restraints - Stress Corrosion Cracking of High Strength Bolts) - Methods to Manage Aging Effects

Mitigation

The effects of stress corrosion cracking of high strength bolts have been mitigated as much as practical by the original selection of materials. The only reported instances of stress corrosion cracking in this material were associated with improper heat treatment or improper material. If such conditions existed at CCNPP, failures would have been experienced soon after installation rather than after many years. Therefore, it is not necessary to provide any additional specific mitigation methods. [Reference 2, Pages 2-4 and 2-10]

Discovery

The effects of stress corrosion cracking of high strength bolting are observable in the form of cracking and failure of bolt material. These conditions would be readily observable during a visual inspection. [Reference 2, Page 5-4]

Group 7 - (Frames and Saddles (inside containment) / LOCA Restraints - Stress Corrosion Cracking of High Strength Bolts) - Aging Management Program(s)

Mitigation:

There are no CCNPP programs credited for mitigation of stress corrosion cracking of high strength bolts.

Discovery

For discovery, the level of aging management activity needed for each category of component supports is determined based on the condition observed during a baseline walkdown of a representative sample of supports of each category. Therefore, discovery activities are discussed in two categories, baseline activities and follow-on aging management activities. The as-found condition during the baseline walkdown dictates the level of follow-on aging management needed for the support type. [Reference 2, Page 6-1 through 6-5]

Baseline Walkdowns

Loss-of-coolant accident restraints (pressurizer support bolting) are subject to baseline inspection under the ISI Program. These completed ISIs serve as an adequate baseline activity to document the condition of these component supports, and the results of the ISIs are maintained at CCNPP. [Reference 2, Page 6-12] The purpose, scope, bases, etc., for the ISI are described above in the subsection, Group 1 - Aging Management Programs.

For the frames and saddles (safety injection tank support bolting), an inspection of the safety injection tank anchor bolting is required. This inspection will be performed using Section XI ISI procedures and techniques even though safety injection tanks are not within normal Section XI ISI scope. This additional sampling baseline walkdown will inspect the safety injection tank anchor bolts for active ARDMs and will document the condition of the anchor bolting. The inspections will be conducted in accordance with the ISI criteria stated above in the subsection, Group 1 - Aging Management Programs. [Reference 2, Page 6-11]

Follow-on Activities

Based on the results of baseline inspections completed per the existing ISI Program requirements, it was determined that continuing ASME Section XI ISIs into the period of extended operations will also serve as an adequate follow-on activity for LOCA restraints (pressurizer support bolting) subject to that program. [Reference 2, Page 5-4]

For frames and saddles (safety injection tank support bolting), the results of the additional baseline walkdowns described above will determine the extent of aging management practices needed for these supports. [Reference 2, Page 6-11]

Group 7 - (Frames and Saddles (inside containment) / LOCA Restraints - Stress Corrosion Cracking of High Strength Bolts) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to stress corrosion cracking of high strength bolts for frames, saddles, and LOCA restraints.

- Group 7 supports associated with components in the scope of license renewal are themselves considered to be within the scope of license renewal because failure of these supports could lead to failure of the supported plant component.
- Stress corrosion cracking of high strength bolts was determined to be a plausible ARDM for the specific Group 7 supports discussed above. The effects of the ARDM are cracking and failure of bolt material that lead to loss of structural adequacy and subsequent loss of strength of the component support. These effects, if left unmanaged, could lead to loss of the intended function of the component supports and ultimately to failure of the supported plant component under CLB conditions.
- Baseline discovery programs include elements that would enable these activities to discover the effect of this plausible aging mechanism and to determine the appropriate level of follow-on aging management activities. The Group 7 supports are either covered by these baseline inspections or additional baseline inspections will be conducted.
- Follow-on discovery activities include continued ISIs and follow-on actions dependent on the results of the additional baseline walkdowns. These activities include elements that would ensure discovery of the effects of this plausible aging mechanism and require corrective action and actions to prevent

recurrence of problem conditions, as appropriate. Group 7 supports within the scope of license renewal are subject to follow-on discovery activities.

- The discovery aging management activities (ISIs, additional baseline walkdowns) detect and correct any adverse effects of stress corrosion cracking of high strength bolts.

Therefore, there is reasonable assurance that the effects of aging will be adequately managed such that the frames, saddles, and LOCA restraints will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

3.1.3 Conclusion

The programs discussed for aging management of component supports are listed in the following table. These programs are (or will be for new programs) administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended function of the Component Supports will be maintained consistent with the CLB during the period of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 3.1-4

LIST OF AGING MANAGEMENT PROGRAMS FOR COMPONENT SUPPORTS

	Program(s)	Credited For
Existing	Snubber Visual Inspection Surveillances	Follow-on discovery activity for snubber supports within the scope of this commodity evaluation. Applies to Group 1.
Existing	Plant Engineering Guideline on System Walkdowns (PEG-7) Control of Shift Activities (NO-1-200) Ownership of Plant Operating Spaces (NO-1-107)	Follow-on discovery activities for component supports covered by completed SVP walkdowns, and for component supports inspected by Additional Baseline Walkdowns (if no active ARDMs are found during additional walkdowns). Applies to Groups 1 through 6.
Existing	Section XI ISI Program	Baseline and follow-on discovery activities for component supports covered by this program. Applies to Groups 1, 2, and 4 through 7.
Modified	Preventive Maintenance Checklists	Follow-on discovery activity for containment air cooler fans (metal spring isolators and fixed bases inside containment). Applies to Group 2.
New	ARDI Program	Baseline walkdown and follow-on activities for 24 inaccessible piping supports outside containment. Plausible ARDMs for these supports are general corrosion, loading due to hydraulic vibration, and loading due to thermal expansion. Applies to Group 1.
New	Additional Baseline Walkdowns	Baseline discovery activity for the component supports not covered or only partially covered by the SVP or the ISI Program, where conditions prevented extrapolation of results to cover these component supports. Applies to Groups 1, 2, and 7.
New	Plant Modification	Modification of Control Room HVAC air handler supports to replace elastomer isolators with spring-type isolators. Applies to Group 3.

3.1.4 References

1. CCNPP Integrated Plant Assessment Methodology, Revision 1, January 11, 1996
2. "Calvert Cliffs Nuclear Power Plant, Aging Management Review of Component Supports," Revision 3, January 1997
3. CCNPP Updated Final Safety Analysis Report, Revision 19
4. CCNPP Engineering Standard ES-040, "Piping Design Criteria," Revision 0, December 1995
5. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
6. Letter from Mr. C. J. Cowgill (NRC) to Mr. G. C. Creel (BGE), dated July 12, 1990, "NRC Region I Resident Inspection Report Nos. 50-317/90-13 and 50-318/90-13 (June 3, 1990 to June 30, 1990)"
7. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated August 17, 1990, "Licensee Event Report 89-07, Revision 1"
8. Letter from Mr. R. W. Reid (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated March 10, 1980, Transmittal of License Amendment Nos. 42 and 25
9. Letter from Mr. R. E. Denton (BGE) to Mr. D. H. Jaffe (NRC), dated July 20, 1984, "Additional Information Regarding Steam Generator Water Hammer Event"
10. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), "Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit 1 (TAC No. M92549) and Unit 2 (TAC No. M92550)," dated December 10, 1996 [Amendment Nos. 217/194]
11. 10 CFR 50.55a, Conditions of Construction Permits
12. American Society of Mechanical Engineers Boiler and Pressure Vessel Code Section XI, 1983 Edition through Summer, 1983 Addenda
13. NRC Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability - ASME Section XI, Division 1"
14. NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in Power Plants," dated March 17, 1988
15. CCNPP Administrative Procedure MN-3, "Pressure Boundary Codes and Special Processes Program"
16. CCNPP "1995 Unit #2 ISI Outage Summary Report," Report Generated by CCNPP Procedure MN-3-110, dated July 13, 1995
17. CCNPP "1996 Unit #1 ISI Outage Summary Report," Report Generated by CCNPP Procedure MN-3-110, dated October 16, 1996
18. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Dr. T. J. Murley (NRC), dated October 19, 1984, "I&E Bulletins 79-02, 79-04, 79-07 and 79-14"
19. CCNPP Plant Engineering Section Guideline PEG-7, "System Walkdowns," Revision 4, November 1995

20. CCNPP Engineering Standard ES-002, “Pipe Support Inspection,” Revision 0, October 11, 1995
21. CCNPP Administrative Procedure NO-1-200, “Control of Shift Activities,” Revision 8, September 10, 1996
22. CCNPP Administrative Procedure NO-1-107, “Ownership of Plant Operating Spaces,” Revision 2, October 28, 1996
23. 10 CFR 50.54, Conditions of Licenses
24. 10 CFR Part 50, Appendix R, Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979
25. 10 CFR Part 55, Operators’ Licenses
26. INPO 84-021 (OP-204), “Conduct of Operations,” Revision 1, July 1991
27. INPO 84-030 (OP-206), “Generic Round Sheets and Shift Operating Practices,” Revision 2, June 1991
28. INPO 85-017, “Guidelines for the Conduct of Operations at Nuclear Power Stations,” Revision 2, April 1992
29. INPO 87-018 (OP-212), “Operations Communications Verbal,” June 1985
30. INPO SOER 87-01, “Core Damaging Accident Following an Improperly Conducted Test,” February 20, 1987
31. NRC IE Circular 80-21, “Regulation of Refueling Crews,” dated September 10, 1980
32. NUREG-0737, “Clarification of TMI Action Plan Requirements,” November 1980
33. CCNPP Administrative Procedure NO-1, “Nuclear Operations Program”
34. Regulatory Guide 1.114, “Guidelines on Being the Operator at the Controls of a Nuclear Power Plant”
35. CCNPP Administrative Procedure QAP 92-15, “Policy for Control Room Watch Coverage”
36. INPO 87-023, Good Practice MA-312, “Plant Inspection Program”, October 1987
37. CCNPP Fourth Quarter Safety Performance Evaluation - 1995
38. CCNPP Technical Procedure STP-M-12-1, “Unit 1 Accessible Snubber Visual Inspection,” Revision 13, January 29, 1997
39. CCNPP Technical Procedure STP-M-12-2, “Unit 2 Accessible Snubber Visual Inspection,” Revision 14, January 3, 1996
40. CCNPP Technical Procedure STP-M-13-1, “Unit 1 Inaccessible Snubber Visual Inspection,” Revision 16, January 30, 1997
41. CCNPP Technical Procedure STP-M-13-2, “Unit 2 Snubber Inspection (Inaccessible),” Revision 13, January 3, 1996
42. Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment, dated February 1992, copyright Seismic Qualification Utility Group (SQUG), Revision 2, corrected February 14, 1992

43. Engineered Materials Handbook, Volume 2, "Engineering Plastics," ASM International 1988

3.1A Piping Segments that Provide Sructural Support

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing piping segments that provide structural support. This section should be reviewed in conjunction with Section 3.1, Component Supports. The items in this section have been evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

3.1A.1 Scoping

3.1A.1.1 Piping Segments that Provide Structural Support Commodity Scoping

Commodity Description/Conceptual Boundaries

The purpose of this section is to document the commodity approach used to evaluate the aging management of the pipe beyond the safety-related/non-safety-related (SR/NSR) boundary to the first seismic restraint(s), which provide the structural support for the functional boundary isolation valve(s) or isolation points. Figure 3.1A-1 below is a simplified drawing that illustrates the piping of concern between points A and B.

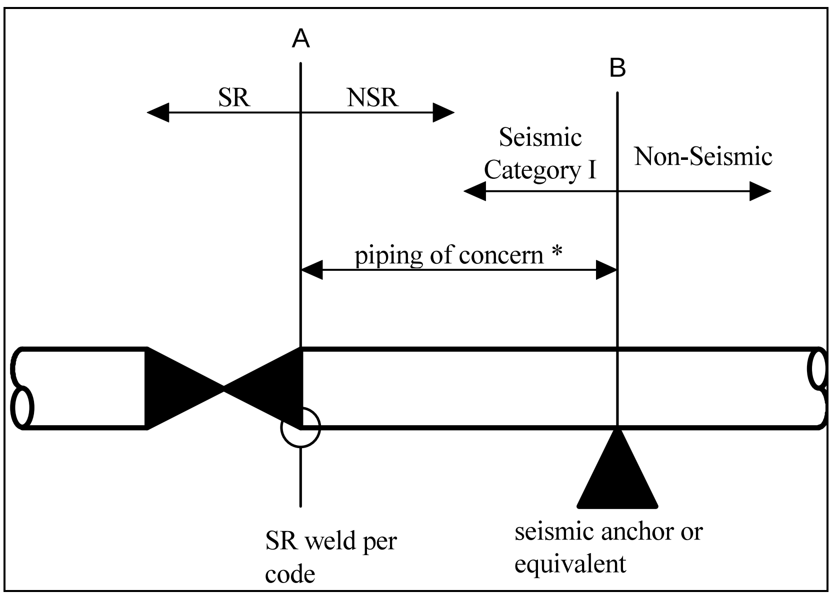

Figure 3.1A-1 (simplified)

(* piping supports in this region are covered in Section 3.1 of the BGE LRA, Component Supports)

The SR/NSR functional boundary includes a transition in safety and, in some cases, piping classifications. The structural integrity of the boundary valve, which functions as the system pressure boundary, must not be compromised. Therefore, the system's seismic structural boundary extends beyond the valve to the first seismic anchor or equivalent. In some instances, the valve itself may be anchored. However, in most cases, the anchor is beyond the valve; and the support system includes the piping segments that provide structural support for the boundary valve. Collectively, these components act as a single "support system."

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3.1A PIPING SEGMENTS THAT PROVIDE STRUCTURAL SUPPORT

These components ensure the integrity of the SR/NSR functional boundary under all design basis loading conditions.

The design loading conditions for these piping segments include factors such as dead loads, thermal loads, and seismic loads. Supporting information for loading conditions of specific supports is maintained onsite. [Reference 1, Appendix 5A] Basic design basis information for piping segments is discussed in UFSAR Chapters 1 (Principal Architectural and Engineering Criteria for Design) and 5A (Structural Design Basis).

Intended Functions

The piping segments beyond SR/NSR boundaries have the intended function of providing structural support under all current licensing basis design loading conditions for SR components within the scope of license renewal.

Piping Segments Requiring Aging Management Review

Because the intended function listed above is provided without moving parts or without a change in configuration or properties, it is a passive intended function. Therefore, the piping segments between the SR/NSR boundary and the seismic anchor are within the scope of license renewal and are also subject to aging management review.

The scope of this section includes all piping segments beyond the SR/NSR functional boundary that perform the intended function of providing structural support to the SR piping and boundary isolation valve or isolation point (see Figure 3.1A-1).

All fluid systems containing SR piping are within the scope of license renewal, as shown in Table 3.1A-1. These systems have the potential for SR/NSR functional boundaries with Seismic Category I boundaries extending beyond them.

TABLE 3.1A-1

SYSTEMS WITHIN THE SCOPE OF LICENSE RENEWAL WITH POTENTIAL FOR CONTAINING PIPING SEGMENTS BEYOND SR/NSR BOUNDARIES
(CCNPP system numbers are shown in parentheses)

System	Associated BGE LRA Section
(011) Service Water Cooling	Section 5.17
(012) Saltwater Cooling	Section 5.16
(013) Fire Protection	Section 5.10
(015) Component Cooling	Section 5.3
(019) Compressed Air	Section 5.4
(023) Diesel Fuel Oil	Section 5.7
(024) Emergency Diesel Generators	Section 5.8
(029) Plant Heating	Section 5.5
(036) Auxiliary Feedwater	Section 5.1
(037) Demineralized Water/Condensate Storage	Section 5.10
(038) Sampling System (Nuclear Steam Supply System)	Section 5.13
(041) Chemical and Volume Control	Section 5.2
(045) Feedwater	Section 5.9
(046) Extraction Steam	Section 5.12
(051) Plant Water	Section 5.5
(052) Safety Injection	Section 5.15
(053) Plant Drains	Section 5.5
(061) Containment Spray	Section 5.6
(064) Reactor Coolant	Section 4.1
(067) Spent Fuel Pool Cooling	Section 5.18
(069) Waste Gas	Section 5.5
(071) Liquid Waste	Section 5.5
(074) Nitrogen and Hydrogen	Section 5.12
(077/79) Area and Process Radiation Monitoring	Section 5.14
(083) Main Steam	Section 5.12

3.1A.2 Aging Management

The plausible age-related degradation mechanisms (ARDMs) for each piping segment beyond the SR/NSR boundary are the same ARDMs as those identified in their respective fluid system discussions listed in Table 3.1A-1. These are the ARDMs that could lead to degradation and the potential for loss of the passive intended structural support function.

The piping segments beyond the SR/NSR boundary are classified as Seismic Category I up to and including the first seismic anchor. Given the similarity of the piping materials for piping within the SR pressure boundary, to those outside this boundary that are designed and maintained to SR requirements, any material degradation identified on the pipe segments within the SR pressure boundary would lead to an evaluation for generic implications on the NSR side of this boundary. In addition, the aging management programs credited in the fluid systems listed in Table 3.1A-1 in conjunction with the CCNPP Corrective Actions Program will ensure that the intended function of providing structural support to the SR pipe and boundary isolation valves or isolation points will be maintained under current licensing basis design loading conditions during the period of extended operation. The programs for aging management of the fluid systems listed in Table 3.1A-1 are referenced in previous BGE LRA submittals as noted in this table.

3.1A.3 Conclusion

The piping segments beyond the SR/NSR functional boundary will be managed by the programs already credited in the Sections of the BGE LRA for the SR portion of the systems listed in Table 3.1A-1. These programs will manage the aging mechanisms such that the intended structural function of the piping segments beyond the SR/NSR boundary up to the first anchor point or equivalent will be maintained consistent with the current licensing basis during the period of extended operation.

3.1A.4 Reference

1. "CCNPP Updated Final Safety Analysis Report," Revision 21

3.2 Fuel Handling Equipment and Other Heavy Load Handling Cranes

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing Fuel Handling Equipment (FHE) and other Heavy Load Handling Cranes (HLHC). The FHE and HLHC were evaluated as a "commodity" in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

3.2.1 Fuel Handling Equipment and other Heavy Load Handling Cranes Commodity Scoping

The system level scoping results identified five systems within the scope of license renewal that are related to FHE and HLHC. Because the only intended functions of these five systems are structural in nature, these five systems are included in a commodity evaluation instead of being addressed individually in the standard IPA process. The five systems are listed below: [Reference 1, page 68]

- Spent Fuel Storage;
- Refueling Pool;
- New Fuel Storage and Elevator;
- Fuel Handling; and
- Cranes

This section begins with a description of the five systems that are related to FHE and HLHC. The intended functions of FHE and HLHC are listed and used to identify the components within the scope of license renewal (i.e., those required to perform the intended functions). Finally, the components subject to Aging Management Review (AMR) are identified and dispositioned in accordance with the CCNPP IPA Methodology.

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently assigned cognizant CCNPP personnel.

<u>Commodity Description/Conceptual Boundaries</u>

In general, the CCNPP IPA Methodology for structures addresses all structural support functions for equipment housed by a particular structure. [Reference 1, Section 7.2.2] However, because of the effect that their failure could have on plant operations, this section of the BGE LRA presents evaluations for (a) components involved in fuel handling and transfer; and (b) cranes that routinely lift heavy loads over safety-related components. There are five systems at CCNPP with components that comprise the FHE and HLHC: Spent Fuel Storage, Refueling Pool, New Fuel Storage and Elevator, Fuel Handling, and Cranes. [Reference 2]

- <u>Spent Fuel Storage</u>: The Spent Fuel Storage System, also referred to as the spent fuel pool (SFP), is divided into two halves and is located in the Auxiliary Building. The pool is constructed of reinforced concrete and lined with stainless steel. Spent fuel assemblies are placed in stainless steel storage racks grouped in parallel rows. Cooling is provided by the SFP Cooling System. [Reference 3, Section 9.7.2.1] Additional components in the SFP include the following:

Spent Fuel Shipping Cask Support Platform - The spent fuel shipping cask pit is located on the Unit 1 side of the dividing wall in the SFP. The floor of the pit is equipped with an energy-absorbing cask support platform that accommodates the various transfer casks used at CCNPP, and provides a second level of protection for the floor of the SFP beyond that provided by the single-failure-proof crane. The platform is comprised of a stainless steel shell that encloses an aluminum honeycomb material which can absorb the impact energy of a spent fuel cask dropped from the single-failure-proof crane. [Reference 3, Section 9.7.2.3]

Spent Fuel Pool Platform - The SFP platform is a portable work platform with removable railings that provides an efficient work site for various maintenance activities involving fuel assemblies. These have included repair of worn fuel assembly guide tubes, eddy current tests, capsule exchanges, and fuel assembly reconstitution. The aluminum work platform is supported by stainless steel structural members and can be located along the west wall of the north (Unit 1) pool, or the east wall of the south (Unit 2) pool. [Reference 3, Section 9.7.2.8]

- Refueling Pool: The refueling pool is formed when the refueling cavity around the upper portion of the reactor vessel (RV) is filled with water from the refueling water tank via the SFP cooling pumps. The refueling pool is constructed of reinforced concrete and lined with stainless steel. The refueling pool interfaces with the SFP via the fuel transfer tube, the Safety Injection System, and the Spent Fuel Pool Cooling System. [Reference 4, Table 1] A four-cell incore instrumentation (ICI) trash rack is located in the lower portion of each unit's refueling canal adjacent to the upender machine. Containers of discarded ICI waste or new/spent fuel assemblies are temporarily placed in this stainless steel rack to facilitate handling during refueling. [Reference 3, Section 9.7.2.2]

- New Fuel Storage and Elevator: The New Fuel Storage and Elevator System consists of the new fuel dry storage racks and the new fuel inspection machine (the new fuel inspection platform). It does not include the new fuel elevator which is in the Fuel Handling System discussed below. The new fuel inspection machine is located near the new fuel storage area. The machine is designed to automatically check the straightness and sectional size of a fuel bundle through its full length. [Reference 2, Section 1.1.1; Reference 5]

- Fuel Handling: The Fuel Handling System includes those components used to move fuel from the time of receipt of new fuel to the storage of spent fuel in the SFP. The system includes:

  New Fuel Elevator - The new fuel elevator lowers new fuel assemblies into the SFP where the spent fuel handling machine (SFHM) is able to grapple and transfer the fuel to the desired pool location. The new fuel elevator is located in the Unit 1 end of the SFP. [Reference 3, Section 9.7.2.7]

  Spent Fuel Handling Machine - The SFHM, also referred to as the fuel pool service platform, is a bridge and trolley arrangement that rides on rails set in concrete on each side of the SFP. The SFHM functions to transfer fuel between the storage locations in the SFP, the new fuel elevator, the spent fuel inspection elevator, the SFP upending machine, or a spent fuel shipping cask, as necessary. [Reference 3, Section 9.7.2.7]

Fuel Upending Machines - There are two fuel upending machines for each unit, one in the Containment Structure refueling pool and the other in the SFP. Each consists of a structural steel support base from which an upending straddle frame is pivoted. The straddle frame engages the fuel carrier. When the carriage with its fuel carrier is in position within the upending frame, the pivots for the fuel carrier and the upending frame are coincident. Hydraulic cylinders attached to both the upending frame and the support base rotate the fuel carrier between a vertical and horizontal position, as required. [Reference 3, Section 9.7.3.2] During the 1996 Unit 1 refueling outage, four fillet welds connecting structural members on the fuel upending machine in the refueling pool failed. It was determined that original joint design, original fabrication, and subsequent changes to machine operations led to low-cycle fatigue failure of the welds. A nodal analysis of the fuel upending machine design determined that addition of stiffeners at the weld joints and use of dual hydraulic cylinders for machine operation would make future fatigue failure of these welds unlikely. These recommendations were implemented for both fuel upending machines in Unit 2, and will be completed for the fuel upending machines in Unit 1 prior to their next scheduled use in moving fuel. Since normal service loads result in stresses that are far below the allowable stress range for the modified stainless steel structural members, fatigue is not plausible for these FHE subcomponents. [Reference 2, Attachment 6]

Transfer Carriage - The transfer carriage transports one or two fuel assemblies through the transfer tube between the refueling pool and the SFP. The carriage is driven by stainless steel cables connected to the carriage and through sheaves to its driving winches mounted below the operating floor level. The fuel carrier is mounted on the carriage and is pivoted for tilting by the upending machines. [Reference 3, Section 9.7.3.2]

Reactor Refueling Machine - The reactor refueling machine (RRM) is a traveling bridge and trolley that spans the refueling pool and moves on rails. The bridge and trolley movement allow coordinate location for the fuel handling mast and hoist assembly over the fuel in the core. [Reference 3, Section 9.7.3.1] The RRM mast and hoist assembly is used for transporting and positioning fuel assemblies in the core and over the upending machine in the refueling pool. The RRM auxiliary hoist is used in conjunction with the control element assembly handling tool to exchange control element assemblies within the reactor core during refueling. [Reference 3, Section 9.7.3.3]

Spent Fuel Inspection Elevator - The spent fuel inspection elevator is similar to the new fuel elevator, but is equipped with a fixed underwater periscope. Fuel assemblies are raised and lowered in front of the periscope to permit fuel inspection. The spent fuel inspection elevator has additional design features to prevent the hoist from raising fuel above the point where adequate water for shielding is available. The spent fuel inspection elevator is located in the Unit 2 end of the SFP. [Reference 3, Section 9.7.2.7; Reference 6]

- Cranes: The Crane System consists of all cranes, monorails, and hoisting and jib equipment at CCNPP. This includes approximately 85 cranes, which can be grouped into three types: overhead gantry cranes, monorail systems and underhung cranes, and overhead hoists. The mechanical components of the Crane System include overhead monorail systems, cranes, monorail tracks, carriers or trolleys, motor-driven electric hoist carriers, gears, hoists, hooks, bridges, and lift-drop sections. Electrical components include motors, connectors, contactors, electric lift and drop sections, motor starters, and control panels. [Reference 2, Section 1.1.1]

In addition to the components described above, this section of the BGE LRA addresses the structural load handling devices designed to transfer the loads of the RV head to the polar crane (PC). These items are the RV cooling shroud (part of the Primary Containment Heating and Ventilating System -- see Section 5.11 of the BGE LRA), and the RV head lift rig (part of the Reactor Vessel Internals System -- see Section 4.3 of the BGE LRA). [Reference 2, Section 1.1.1; Reference 4, Table 1]

Scoped Structures and Components and Their Intended Functions

The FHE and HLHC is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the FHE and HLHC were determined based on the requirements of §54.4(a)(1) and (2) and in accordance with the CCNPP IPA Methodology Section 7.2.2: [Reference 2]

- Provide structural and/or functional support to safety-related equipment;
- Provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the intended safety-related functions; and
- Support single-failure-proof criteria for lifting heavy loads over the SFP.

No intended functions of the FHE and HLHC were determined based on the requirements of §54.4(a)(3).

Components Subject to AMR

The IPA procedure was used to identify all components that provided at least one of the structural intended functions listed above. From all components in the five systems that comprise this commodity, those that are subject to AMR were determined as follows:

- Structural components and subcomponents that perform the first function listed above are the Spent Fuel Cask Handling Crane ([SFCHC] discussed separately below), the SFP (reinforced concrete and steel liner), the refueling pool (reinforced concrete and steel liner), the fuel transfer tube (steel liner), the spent fuel shipping cask support platform, and storage racks for new fuel, spent fuel, and ICI waste. [Reference 2, Attachment 2] These items are classified as safety-related in the CCNPP Quality List, and are required to meet Seismic Category I criteria because they must remain functional before, during, or after a safe shutdown earthquake. [Reference 7, pages 46, 57, 58, 68, 82, and 83]
- Structural subcomponents of the following items perform the second function listed above: [Reference 2, Attachment 2]

  The SFP Platform;

  The equipment involved in fuel handling and transfer (i.e., the spent fuel inspection elevator, the new fuel elevator, the fuel upending machines, the RRM, and the SFHM);

  The load handling equipment used for RV head removal/installation (i.e., the RV head lift rig and the RV cooling shroud); and

Those cranes at CCNPP that are subject to the general guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants Resolution of Generic Technical Activity A-36" (i.e., the PC, the Intake Structure Semi-Gantry Crane (ISSGC), and the Transfer Machine Jib Crane).

NOTE: These three cranes handle heavy loads (i.e., loads in excess of 1600 lbs.) in the vicinity of the RV, near spent fuel in the SFP, or in areas where a load drop may damage safe shutdown or decay heat removal equipment. Other components in the Cranes System are excluded from the restrictions of NUREG-0612 because (1) the lift points and the safe shutdown equipment are adequately separated; or (2) the largest load lifted is not a heavy load. [Reference 3, Section 5.7]

These items are functionally non-safety-related, but must be considered safety-related on a structural basis only. They are categorized as Seismic II/I at CCNPP because their failure or excessive movement could cause failure of a safety-related structure, system, or component. [Reference 7, pages 62, 68, 82, 83, and 92]

- Structural subcomponents of the SFCHC perform the first and third functions listed above. [Reference 2, Attachment 2] This crane is designed in accordance with the single-failure-proof criteria of NUREG-0554, "Single Failure Proof Cranes for Nuclear Power Plants," and NUREG-0612. [Reference 3, Section 5.7]

Per the license renewal rule, ". . . Structures and components subject to an aging management review shall encompass those structures and components (i) That perform an intended function, as described in §54.4 without moving parts or without a change in configuration or properties . . . and (ii) That are not subject to periodic replacement based on a qualified life or specified time period . . . " The scoping process determined that some structural devices, such as drums, hydraulic cylinders, and wheels, performed their intended function(s) while in motion. Such devices were considered to be active subcomponents and were eliminated from AMR. [Reference 2, Attachment 1] It was conservatively assumed that no structural components or subcomponents in the FHE and HLHC were replaced based on time or qualified life. [Reference 1, page 69]

Based on the results of the process described above, the portion of the FHE and HLHC that is within the scope of license renewal and subject to AMR includes 57 structural components and their supports.

Some of the FHE and HLHC components were already addressed for their structural intended function(s) as parts of the buildings in which they are housed in Section 3.3 of the BGE LRA, and are therefore not covered in this section. These components are listed below:

- PC Girders;
- SFCHC Rail/Support Girders;
- Refueling Pool Reinforced Concrete;
- Refueling Pool Stainless Steel Liner;
- Fuel Transfer Tube Stainless Steel Liner;
- Spent Fuel Pool Reinforced Concrete;
- Spent Fuel Pool Stainless Steel Liner;
- Spent Fuel Pool Storage Racks; and
- New Fuel Storage Racks.

The remaining 48 components, listed in Table 3.2-1, are subject to AMR and are evaluated within this section.

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

3.2.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the FHE and HLHC components is given in Table 3.2-1, with plausible ARDMs identified by a check mark (✓) in the appropriate component row. [Reference 2, Tables 4-1 and 4-3] For efficiency in presenting the results of these evaluations in this report, ARDM/component combinations are grouped together where there are similar characteristics and the discussion is applicable to all components within that group. Table 3.2-1 also identifies the group to which each ARDM/component combination belongs. The following groups have been chosen for the components of the FHE and HLHC:

Group 1: General Corrosion/Oxidation for FHE and HLHC carbon steel components (i.e., all except the RV cooling shroud structural support members);

Group 2: General Corrosion/Oxidation and Corrosion due to Boric Acid for the RV cooling shroud structural support members;

Group 3: Fatigue for the PC rails; and

Group 4: Fatigue, Wear, and Mechanical Degradation/Distortion for wire rope.

TABLE 3.2-1

POTENTIAL AND PLAUSIBLE ARDMs FOR THE FHE AND HLHC SYSTEM

FHE/HLHC Components	General Corrosion / Oxidation	Pitting / Crevice Corrosion	SCC / IGSCC / IGA	MIC	Elevated Temp-erature	Irradiation	Stress Relaxation	Fatigue	Wear	Mechanical Degrada-tion / Distortion	Corrosion due to Boric Acid
Spent Fuel Shipping Cask SS Support Platform											
ICI Trash Racks SS Structural Members											
Spent Fuel Pool Platform SS Structural Members											
Spent Fuel Inspection Elevator subcomponents (Unit 2 only):											
• SS Structural Members											
• SS Hoisting Ropes								✓(4)	✓(4)	✓(4)	
New Fuel Elevator subcomponents (Unit 1 only):											
• SS Structural Members											
• SS Hoisting Ropes								✓(4)	✓(4)	✓(4)	
Fuel Upending Machine and Transfer Carriage subcomponents:											
• SS Structural Members											
• SS Hoisting Ropes & Drive Cables								✓(4)	✓(4)	✓(4)	
RRM subcomponents:											
• CS Rails, Clips, Spacers, Bolts & Stops	✓(1)										
• CS Bridge End Trucks & Axles	✓(1)										
• CS Bridge Girders	✓(1)										
• CS Trolley Rails	✓(1)										
• CS Trolley Structural Members	✓(1)										
• CS Auxiliary Hoist Frame	✓(1)										
• SS Hoisting Ropes								✓(4)	✓(4)	✓(4)	
SFHM subcomponents:											
• CS Rails, Clips, Spacers, Bolts & Stops	✓(1)										
• CS Bridge End Trucks & Axles	✓(1)										
• CS Bridge Girders	✓(1)										
• CS Trolley Rails	✓(1)										
• CS Trolley Structural Support Members	✓(1)										
• SS Hoisting Ropes								✓(4)	✓(4)	✓(4)	

TABLE 3.2-1 (continued)

POTENTIAL AND PLAUSIBLE ARDMs FOR THE FHE AND HLHC SYSTEM

FHE/HLHC Components	General Corrosion / Oxidation	Pitting / Crevice Corrosion	SCC / IGSCC / IGA	MIC	Elevated Temp-erature	Irradiation	Stress Relaxation	Fatigue	Wear	Mechanical Degrada-tion / Distortion	Corrosion due to Boric Acid
SFCHC subcomponents:											
• CS Crane Rails, Clips, Bolts & Stops	✓(1)										
• CS Bridge End Trucks	✓(1)										
• CS Bridge Girders	✓(1)										
• CS Trolley Rails	✓(1)										
• CS Trolley Structural Support Members	✓(1)										
• IPS Hoisting Ropes (Main Hoist)	✓(1)							✓(4)	✓(4)	✓(4)	
• SS Hoisting Ropes (Auxiliary Hoist)								✓(4)	✓(4)	✓(4)	
PC subcomponents:											
• CS Crane Rails, Clips, Bolts & Stops	✓(1)							✓(3) (Rails only)			
• CS Bridge End Trucks	✓(1)										
• CS Bridge Girders	✓(1)										
• CS Trolley Rails	✓(1)										
• CS Trolley Structural Support Members	✓(1)										
• Alloy Steel Hoisting Ropes	✓(1)							✓(4)	✓(4)	✓(4)	
ISSGC subcomponents:											
• CS Rails, Clips, Bolts & Stops	✓(1)										
• CS Gantry End Trucks	✓(1)										
• CS Gantry Structural Members	✓(1)										
• CS Bridge Girders	✓(1)										
• CS Trolley Structural Support Members	✓(1)										
• CS Trolley Rails	✓(1)										
• IPS Hoisting Ropes	✓(1)							✓(4)	✓(4)	✓(4)	

TABLE 3.2-1 (continued)

POTENTIAL AND PLAUSIBLE ARDMS FOR THE FHE AND HLHC SYSTEM

FHE/HLHC Components	General Corrosion / Oxidation	Pitting / Crevice Corrosion	SCC / IGSCC / IGA	MIC	Elevated Temp-erature	Irradiation	Stress Relaxation	Fatigue	Wear	Mechanical Degrada-tion / Distortion	Corrosion due to Boric Acid
Transfer Machine Jib Crane subcomponents:											
• CS Structural Members	✓(1)										
• CS Bolts	✓(1)										
• SS Hoisting Ropes								✓(4)	✓(4)	✓(4)	
Load Handling Equipment used for RV Head Removal/Installation:											
• RV Head Lift Rig	✓(1)										
• RV Cooling Shroud CS Structural Support Components	✓(2)										✓(2)
Hooks for all HLHC	✓(1)										

✓ - indicates plausible ARDM determination
(#) - indicates the group(s) in which the ARDM/component combination is evaluated

Components
FHE - Fuel Handling Equipment
HLHC - Heavy Load Handling Cranes
ICI - Incore Instrumentation
ISSGC - Intake Structure Semi-Gantry Crane
PC - Polar Crane
RRM - Reactor Refueling Machine
RV - Reactor Vessel
SFCHC - Spent Fuel Cask Handling Crane
SFHM - Spent Fuel Handling Machine

ARDMs
IGA - Intergranular Attack
IGSCC - Intergranular Stress Corrosion Cracking
MIC - Microbiologically-Induced Corrosion
SCC - Stress Corrosion Cracking

Materials
CS - Carbon Steel
IPS - Improved Plow Steel
SS - Stainless Steel

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

Group 1 - (general corrosion/oxidation for FHE and HLHC carbon steel components) - Materials and Environment

The components of the FHE and HLHC for this group are fabricated of various grades of steel. [Reference 2, Attachment 3] Austenitic stainless steel and nickel-base alloys are quite resistant to general corrosion/oxidation. [Reference 2, Attachment 5] Therefore, general corrosion/oxidation is considered a potential ARDM only for those components constructed of carbon steel, improved plow steel, or alloy steel.

Except for the ISSGC, the structural components in Group 1 are exposed to climate-controlled environments inside the Containment and Auxiliary Buildings. Inside Containment, the maximum design relative humidity and ambient air temperature for normal plant operations are 70% and 120°F, respectively. [Reference 8, page 62] In the Auxiliary Building, components in this group are subjected to a maximum design temperature of 110°F, with a maximum relative humidity of 70%. [Reference 8, pages 54 through 59] Some FHE and HLHC components are located near the SFP, where condensation in the presence of oxygen could lead to oxidation. Additionally, some places can harbor pockets of liquids that may be inaccessible for visual inspection without removing interference. Carbon steel located in these areas may be subjected to more severe local environments. [Reference 2, Attachment 6]

The ISSGC is subjected to the outdoor environment above the Intake Structure. There is no heavy industry nearby CCNPP to add chemicals to the atmosphere but, due to the close proximity of the Chesapeake Bay, the ISSGC could be exposed to condensation and saltwater. [Reference 2, Attachment 6; Reference 3, Sections 2.8 and 2.10]

Since corrosion was considered a potential degradation mechanism for all structural steel components, its effects were considered in the original design of the FHE and HLHC components. As a result, all exposed structural steel surfaces of these components in the Containment, Auxiliary Building, and Intake Structure received a protective coating during the construction phase. [References 9 through 17] Additionally, lubricants were specified for improved plow steel and alloy steel hoisting ropes. [References 10 and 14]

Group 1 - (general corrosion/oxidation for FHE and HLHC carbon steel components) - Aging Mechanism Effects

General corrosion/oxidation is the thinning of metal by chemical attack at its surface by an aggressive environment of moisture and oxygen. Steel corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. Initially, the exposed steel surface reacts with oxygen and moisture to form an oxide film as rust. Once the protective oxide film has been formed and if it is not disturbed by erosion, alternating wetting and drying, or other surface actions, the oxidation rate will diminish rapidly with time. Chlorides increase the rate of corrosion by increasing the electrochemical activity. [Reference 2, Attachment 5; Reference 18, Attachment 1]

Corrosion products such as hydrated oxides of iron (rust) form on exposed, unprotected surfaces of the steel and are readily visible. The affected surface may degrade to such an extent that visible perforation may occur. In the case of exposed surfaces of FHE and HLHC carbon steel components with protective coatings, corrosion may cause the protective coatings to lose their ability to adhere to the corroding surface. For wire rope, scrubbing (i.e., rubbing against itself, sides of sheaves, or other objects) may cause removal of the lubricant. In these cases, damage to the coatings can be visually detected well in advance of significant degradation of the steel. Additionally, some carbon steel components could be exposed locally to elevated temperatures (e.g., areas close to motors), which would not affect component function, but may cause the coatings to fail (e.g., paint flaking, lubricant drying out) and allow oxidation to occur. [Reference 2, Attachment 6]

The outdoor saltwater atmosphere has affected the protective coatings of structural members of the ISSGC. Visual inspections of the ISSGC revealed considerable corrosion on carbon steel surfaces where protective coatings had deteriorated. [Reference 2, Attachment 6] The results of such visual inspections are documented and corrective actions taken to repair the surfaces, as needed.

If general corrosion/oxidation is left unmanaged for an extended period of time, the resulting loss of carbon steel material could lead to the inability of the structural components identified in Table 3.2-1 to perform their intended functions under current licensing basis (CLB) design loading conditions. [Reference 2, Attachment 5]

Group 1 - (general corrosion/oxidation for FHE and HLHC carbon steel components) - Methods to Manage Aging

<u>Mitigation</u>: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment and protecting the external surfaces with paint, lubricant, or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces. [Reference 2, Attachment 6]

<u>Discovery</u>: The effects of general corrosion/oxidation of carbon steel are detectable by visual inspection. A visual examination by a person familiar with the components can be used to determine general mechanical and structural condition and check for rust. Observing that significant degradation of protective coatings has not occurred is an effective method to ensure that corrosion has not affected the intended function of the structural component. Since the coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition that triggers corrective action before corrosion that affects the components' ability to perform its intended function can occur. The degradation of the protective coating that does occur can be discovered and monitored by periodically inspecting the carbon steel structural components. Corrective action for failed protective coatings and any actual metal degradation can be carried out as necessary. [Reference 2, Attachment 6]

Group 1 - (general corrosion/oxidation for FHE and HLHC carbon steel components) - Aging Management Program(s)

Mitigation: The exposed metal surfaces of carbon steel structural components are covered by protective coatings that mitigate the effects of corrosion. The discovery programs discussed below verify that the protective coatings of carbon steel structural components are maintained.

Discovery: Periodic inspection of carbon steel structural FHE and HLHC components for the effects of general corrosion/oxidation is controlled through a combination of existing and modified operations and maintenance programs.

- The Calvert Cliffs Operating Manual, NO-1-201, establishes the requirements for implementing and using Operating Instructions as approved, preplanned methods of conducting operations. [Reference 19] The CCNPP Performance Evaluation Program, NO-1-203, has been established to perform periodic operational checks and obtain readings to determine equipment performance, as determined by manufacturers' recommendations, System Engineers' recommendations, and operating needs. [Reference 20] These programs address controls for activities conducted as part of daily shift operations, and apply to operators and others who interact with them. [Reference 21]

  The Performance Evaluation Program provides for checks of the SFHM, RRM, and associated components prior to refueling campaigns (i.e., defuel/refuel or fuel shuffle). The checks for the SFHM are also performed every 90 days. [References 22 and 23] Calvert Cliffs procedure PE 0-81-1-O-Q directs performance of checks in accordance with OI-25A, "Spent Fuel Handling Machine," which requires performing a walkdown for foreign material and cleanliness, inspecting the SFHM and associated equipment for damaged, corroded, or deteriorated parts, and checking cleanliness of rail surfaces. [Reference 24] PE 0-81-2-O-C directs performance of checks in accordance with OI-25C, "Refueling Machine," which requires the same activities for each unit's RRM. [Reference 25]

  As part of the plant's administrative procedures hierarchy, the Operating Manual and the Performance Evaluation Program have been evaluated by the Nuclear Regulatory Commission (NRC) as part of its routine licensee assessment activities. The plant's nuclear operations procedures have numerous levels of controls and reviews, including assignment of responsibility for conducting performance evaluations as required, reviewing all the evaluations for accuracy and completeness, and analyzing data for trends, if applicable. Specific responsibilities are assigned to BGE personnel for monitoring these programs through periodic audits. These controls provide reasonable assurance that the associated activities will continue to be an effective method of monitoring the FHE for the effects of general corrosion/oxidation. [References 19, 20, and 21]

- For activities involving load handling at CCNPP, minimum requirements for inspection and testing of load handling equipment are established by MN-1-104, "Load Handling." In addition to a visual inspection prior to each use, this procedure directs establishment of an annual inspection schedule for visual inspection of cranes, hoists, and wire rope, as well as non-destructive examination (NDE) of hooks for load handling equipment. [Reference 26, Sections 5.7.A.2 and 5.8.A] All inspections are done by qualified operators who have been trained according to American National Standards Institute (ANSI) requirements applicable to the type of crane being inspected. [Reference 26, Section 5.1.B] Periodic inspection results must be documented, and deficiencies that would affect the handling capacity of the equipment, including deformed, cracked, or corroded members, as well as damaged wire rope, must be corrected (through repair or replacement) prior to further use. [Reference 26, Sections 5.8.B and 5.8.C] The procedures in effect at CCNPP comply with NUREG-0612 and the applicable ANSI standards for control of heavy loads. [Reference 27]

The Transfer Machine Jib Crane is used to raise the fuel transfer carriage out of the SFP. This is an infrequent operation which has not been performed to date. [Reference 28] In accordance with MN-1-104, testing and inspection of this crane is required prior to initial use. Inspection results must be documented, and deficiencies that would affect the handling capacity of the equipment, including deformed, cracked, or corroded members, must be repaired prior to further use. [Reference 26, Sections 5.7.A.3 and 5.8.C]

- The CCNPP Preventive Maintenance Program, MN-1-102, has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. The program covers all preventive maintenance activities for nuclear power plant structures and equipment within the plant, including those preventive maintenance activities applicable to the cranes, monorails, and hoisting and jib equipment within the scope of license renewal. [Reference 29]

Preventive Maintenance Tasks are automatically scheduled and implemented in accordance with Preventive Maintenance Program procedures. [Reference 29] The following tasks implement the requirements of MN-1-104 by directing periodic visual inspections and/or NDE for the listed FHE and HLHC components:

00992009	for the SFCHC [References 30 and 31]
10992010, 20992002	for Unit 1, Unit 2 PCs [References 32 and 33]
10992007	for the ISSGC [References 34 and 35]
10642031, 20642030	for Unit 1, Unit 2 RV head lift rigs [Reference 36]

These preventive maintenance tasks will be modified to specify the applicable carbon steel subcomponents and explicitly present inspection requirements for discovery of degraded coatings and material loss that may be caused by general corrosion/oxidation. [Reference 2, Attachment 8]

The CCNPP Corrective Action Program is used to take the necessary corrective actions to ensure that the applicable components will remain capable of performing their intended functions under all CLB loading conditions.

The Preventive Maintenance Program has been evaluated by the NRC as part of its routine licensee assessment activities. The plant Maintenance Program also has had numerous levels of management review, all the way down to the specific implementation procedures. Specific responsibilities are assigned to BGE personnel for evaluating and upgrading the Preventive Maintenance Program, and for initiating program improvements based on system performance. [Reference 29] These assessments and controls provide reasonable assurance that the Preventive Maintenance Program will continue to be an effective method of managing the effects of general corrosion/oxidation on carbon steel FHE and HLHC components.

Group 1 - (general corrosion/oxidation for FHE and HLHC carbon steel components) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion/oxidation of carbon steel FHE and HLHC components:

- The carbon steel components listed in Table 3.2-1 provide structural and/or functional support to safety-related equipment or to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of safety-related functions. Those components associated with the SFCHC also support single-failure-proof criteria for lifting heavy loads over the SFP. These functions must be maintained under CLB design loading conditions.
- FHE and HLHC components are exposed to moisture and oxygen in their installed locations.
- Carbon steel, improved plow steel, and alloy steel corrode in the presence of moisture and oxygen, which leads to a loss of material. This could eventually result in inability of the affected components to perform their intended function(s).
- Coatings, specified during original construction, mitigate the effects of corrosion by providing a protective layer that prevents moisture and oxygen from contacting the steel.
- Periodic inspection of the FHE and HLHC components under the Performance Evaluation Program, and the load handling procedure, as applicable, detects general corrosion/oxidation of carbon steel components and degradation of their protective coatings, documents unsatisfactory conditions, and initiates appropriate corrective action.
- Existing preventive maintenance tasks will be modified to provide for periodic visual inspection of applicable FHE and HLHC components, with specific requirements to detect the effects of general corrosion/oxidation of carbon steel subcomponents. This ensures that corrective actions will be taken such that there is a reasonable assurance that structural functions will be maintained.

Therefore, there is a reasonable assurance that the effects of general corrosion/oxidation will be managed for the carbon steel FHE and HLHC components listed in Table 3.2-1 such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operations.

Group 2 - (general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members) - Materials and Environment

The RV cooling shroud structural support members are bolted to the RV head and are fabricated of carbon steel. [References 16 and 17] Inside Containment, the maximum design relative humidity for normal plant operations is 70%. [Reference 8, page 62] The design maximum temperature around the RV cooling shroud structural support members is 150.6°F. [Reference 8, page 19] Condensation in the presence of oxygen could lead to oxidation. Additionally, some internal portions of the RV cooling shroud can harbor pockets of liquids that may be inaccessible for visual inspection without removing interference. Carbon steel located in these areas may be subject to more severe local environments. [Reference 2, Attachment 6] The bolted connections at the interface of the RV head and the RV cooling shroud structural support members are not normally exposed to borated water because they are all external to the vessel, but they may be exposed to boric acid as a result of leakage at the RV head penetrations. [Reference 2, Attachment 5]. Therefore, general corrosion/oxidation and corrosion due to boric acid are considered potential ARDMs for the RV cooling shroud structural support members.

Group 2 - (general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members) - Aging Mechanism Effects

Carbon steels are particularly susceptible to significant acceleration of general corrosion effects (described in Subsection Group 1, Aging Mechanism Effects, above) when exposed to boric acid in the concentrations present in primary coolant. Leakage of boric acid from RV head penetrations can result in the formation of concentrated deposits of boric acid in the form of crystals at the anchorage of the RV cooling shroud due to evaporation caused by the very high external temperature of the RV head. The consequences of this damage are loss of load-carrying cross-sectional area and weakened structural integrity. [Reference 2, Attachment 5]

Visual inspections of the RV head, which are performed during refueling outages, have found boric acid crystallization at the bolted connections between the RV cooling shroud structural support members and the RV head. [Reference 2, Attachment 6] Boric acid crystals discovered at a weep hole in the bottom of the RV cooling shroud during an inspection of the Unit 2 RV head in April 1993 were found to be the result of leakage from a defective seal weld in a modified control element assembly pressure housing. There was no sign of RV head degradation as a result of the leak, and repairs were completed promptly. [Reference 37, Section 7.1]

If either general corrosion/oxidation or corrosion due to boric acid is left unmanaged for an extended period of time, the resulting loss of carbon steel material could lead to the inability of the RV cooling shroud structural support members to perform their intended function under CLB design loading conditions.

Group 2 - (general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment and protecting the external surfaces with paint or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces. [Reference 2, Attachment 6]

Boric acid corrosion can be mitigated by minimizing leakage. The susceptible area (i.e., the RV cooling shroud anchorage to the RV head) can be periodically observed for signs of borated water leakage, and appropriate corrective action can be initiated as necessary to eliminate the leakage, clean spill areas, and assess any corrosion. [Reference 2, Attachment 6]

Discovery: The effects of general corrosion/oxidation and corrosion due to boric acid on the RV cooling shroud structural support members can be discovered through a program of visual inspection of the RV head area. Inspection of the RV cooling shroud, with special attention to the bolted connections at the interface of the RV head and the RV cooling shroud, could identify general corrosion and/or residue from boric acid leakage and result in corrective actions being taken before corrosion could degrade the intended function of the RV cooling shroud structural support members. [Reference 2, Attachment 8]

Group 2 - (general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members) - Aging Management Program(s)

Mitigation: The CCNPP Boric Acid Corrosion Inspection (BACI) Program (MN-3-301, Reference 38) can mitigate the effects of boric acid corrosion through timely discovery of leakage of borated water and removal of any boric acid residue that is found. This program requires visual inspection of the components containing boric acid for leaks, and the removal of any boric acid leakage from component surfaces. The BACI Program also verifies that the protective coatings that mitigate corrosion of the RV cooling shroud structural support members are maintained. [Reference 2, Attachment 8] Further details on the BACI Program are discussed in the Discovery subsection below.

Discovery: Discovery of boric acid leakage is ensured by the BACI Program. [Reference 38] This program also requires investigation of any leakage or corrosion that is found. A visual examination of external surfaces is performed for components containing boric acid, including the RV head penetrations. This program will be modified to specify examinations during each refueling outage of: (a) the RV cooling shroud anchorage to the RV head for evidence of boric acid leakage; and (b) all RV cooling shroud structural support members for general corrosion/oxidation. [Reference 2, Attachment 8]

The Inservice Inspection Program required the establishment of the BACI Program to systematically ensure that boric acid corrosion does not degrade the primary system boundary. [Reference 39, Section 5.8.A.1] The program controls examination, test methods, and actions to minimize the loss of structural and pressure-retaining integrity of components due to boric acid corrosion. [Reference 39, Section 3.0.C] The basis for the establishment of the program is Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." [Reference 38, Section 1.1]

The scope of the program is threefold in that it: (a) identifies locations to be examined; (b) provides examination requirements and methods for the detection of leaks; and (c) provides the responsibilities for initiating engineering evaluations and the necessary corrective actions. [Reference 38, Section 1.2]

During each refueling outage, designated personnel perform walkdown inspections to identify and quantify any leakage found at specific locations inside the Containment and in the Auxiliary Building. The inservice inspection ensures that all components where boric acid leakage has been documented previously are also examined in accordance with the requirements of this program. A second inspection of these components is performed prior to plant startup (at normal operating pressure and temperature) if leakage was identified previously and corrective actions were taken. [Reference 38, Sections 5.1 and 5.2] If either leakage or corrosion is discovered, issue reports are generated in accordance with CCNPP procedure QL-2-100, “Issue Reporting and Assessment,” to document and resolve the deficiency. Corrective actions address the removal of boric acid residue and inspection of the affected components for general corrosion. If general corrosion is found on a component, the issue report provides for evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 38, Section 5.3]

The BACI Program is subject to periodic internal assessment activities. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE’s overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 40, Section 1B.18]

The BACI Program has evolved to account for operational experience. For example, both CCNPP Units have had occurrences of boric acid leakage through the ICI flange connections. [Reference 41, Attachment page 2] Additionally, boric acid crystals discovered at the bottom of the RV cooling shroud were found to be the result of leakage from a defective seal weld in a modified control element assembly pressure housing. [Reference 37, Section 7.1] The BACI Program existed at the time of these events, but only required specific inspection for leaks at the beginning and end of each outage; it did not address leaks discovered outside of normal inspections. [Reference 41, Attachment page 3] As a corrective action, the BACI Program was revised to ensure that all boric acid leaks are evaluated and to specify the minimum qualification level for inspectors evaluating boric acid leaks. Apparent leaks are documented in issue reports by the individual discovering the leak. The reports are then routed to the inservice inspection group for closer inspection and evaluation by a qualified inspector. This approach provides for more boric acid leakage inspection coverage, while still ensuring that appropriately qualified individuals assess and quantify any resultant damage.

The corrective actions taken as a result of the programs described above will ensure that the RV cooling shroud structural support components remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 2 - (general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members:

- The RV cooling shroud structural support members provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of safety-related functions. This function must be maintained under CLB design loading conditions.
- The RV cooling shroud structural support members are fabricated from carbon steel, and the bolted connections at the interface of the RV head and the RV cooling shroud structural support members may be exposed to boric acid leakage from RV head penetrations. They are also exposed to moisture and oxygen in their installed locations.
- Carbon steel corrodes in the presence of moisture and oxygen, which leads to a loss of material. Carbon steels are particularly susceptible to significant acceleration of general corrosion effects when exposed to boric acid in the concentrations present in primary coolant.
- Coatings, specified during original construction, mitigate the effects of corrosion by providing a protective layer that prevents moisture and oxygen from contacting the steel.
- The CCNPP BACI Program will be modified to manage the effects of general corrosion/oxidation and boric acid leakage for the RV cooling shroud structural support members. This program will ensure that leakage and corrosion are discovered and that appropriate corrective action is taken.

Therefore, there is a reasonable assurance that the effects of general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members will be managed such that they will be capable of performing their intended function consistent with the CLB during the period of extended operations.

Group 3 - (fatigue for PC rails) - Materials and Environment

The PC rails are fabricated of carbon steel and installed inside Containment, where the maximum design relative humidity and ambient air temperature for normal plant operations are 70% and 120°F, respectively. [Reference 2, Attachment 3; Reference 8, page 62] The rail mountings utilize a “tight fit” type of design to properly restrain the rail against its design loads. Three rail mounting options are available to connect the PC rails to the crane girder, and any combination of rail connection options can be used. [Reference 42] The PC rails were assembled in sections with expansion joints that allow the rail sections to expand and contract without binding. Extra rail mountings are used at each expansion joint to maintain proper alignment and ensure transfer of load between sections.

When a lifted load is applied, lateral loading causes uplift along the inside of the rail. Torsion and bending are produced about both axes, in combination with a localized stress field in the vicinity of the load. As the load is transferred between rail sections, stress cycles are experienced. It has been conservatively assumed that cracks in the PC rails would propagate under repeated application of lifted loads. Therefore, fatigue is considered a potential ARDM for the PC rails.

Group 3 - (fatigue for PC rails) - Aging Mechanism Effects

Fatigue is a common degradation of structural members produced by periodic or cyclic loadings that are less than the maximum allowable static loading. Fatigue damage results in progressive, localized structural change in materials that have been subjected to fluctuating stresses and strains. Low-cycle fatigue involves a low frequency of high-level, repeated loads. The number of cycles is usually less than 10^5 for steel structures. [Reference 18, Attachment 1]

Fatigue of steel structures is initiated by plastic deformation within a localized region of the structure. A non-uniform distribution of stresses through a cross-section may cause a stress level to exceed the yield point within a small area, and cause plastic movement after the number of stress reversal cycles reaches the material's endurance limit. Such conditions will eventually produce a minute crack. The localized plastic movement further aggravates the non-uniform stress distribution, and further plastic movement causes the existing crack to grow. [Reference 43, Appendix T]

Short PC rail sections installed at the expansion joints contain flame-cut holes that go through the end of each rail section on either side of the expansion joint. These holes were made during installation to permit use of standard splice bars, joint bar bolts, and spring washers with the short PC rail sections, if necessary. [Reference 44] The flame-cut holes result in a non-uniform distribution of stresses through the cross-section of the PC rails, and cracks have been found running radially from flame-cut holes at expansion joints in both Units 1 and 2. These indications were determined to be quench cracks resulting from the hole-burning operation during installation. Since these sections of the PC rails are subject to repeated loading whenever the PC is used for lifting loads, low-cycle fatigue is considered plausible for the PC rails. This aging mechanism, if unmanaged, could result in unstable crack growth under CLB design loading conditions such that the PC rails may not be able to support the lifted loads.

Group 3 - (fatigue for PC rails) - Methods to Manage Aging

Mitigation: Standard PC rail sections were supplied from the steel mill with chamfered holes through the web to permit use of splice bars, if necessary. [References 44 and 45] Cracking has not been observed at any of the holes in the standard PC rail sections at CCNPP, and cracking is considered to be likely only at the flame-cut holes in the short PC rail sections. Center-punching the ends of identified cracks or repairing identified cracks by weld buildup can mitigate the effects of low-cycle fatigue by relieving the stress concentration at the flame-cut holes. Alternately, some or all of the short PC rail sections can be replaced.

Discovery: The effects of fatigue for the PC rails are detectable by visual inspection and NDE. Periodic examination can discover cracks resulting from fatigue, monitor growth of previously identified cracks, verify the effectiveness of crack repairs, and initiate appropriate corrective action prior to failure of the PC rails.

Group 3 - (fatigue for PC rails) - Aging Management Program(s)

Mitigation: In 1992, indications of cracking at six flame-cut holes in the short PC rail sections at the expansion joint at azimuth 177° in Unit 1 were identified during visual examination and quantified using magnetic-particle testing. A fracture mechanics evaluation in 1993 concluded that the peak stress intensity at these holes would exceed the critical stress intensity for unstable crack propagation under maximum design loading conditions. The results of this evaluation prompted repair of the cracks using weld buildup in 1994.

During the 1997 refueling outage, magnetic-particle testing revealed five flame-cut holes at four separate expansion joints in Unit 2, with at least one crack indicated. An engineering evaluation is in progress, with recommendations to base any needed repair/replacement of the PC rails on the results of a fracture mechanics evaluation. [Reference 46]

Discovery: Periodic inspection of the PC rails for the effects of fatigue and the effectiveness of corrective actions is controlled through the existing Preventive Maintenance Program. Preventive Maintenance Tasks 10992001 and 20992000, "Perform NDE on Polar Crane Rails," are automatically scheduled and implemented in accordance with MN-1-102. [Reference 29] These tasks direct visual inspection of the PC rails, and subsequent NDE if there is evidence of cracking. [References 47 and 48] Currently, inspection of the PC rails is performed on a four-to-six-year interval. [Reference 48] Results are evaluated against prior inspection records to verify adequacy of weld repairs, identify trends, and determine the necessity for future inspections. The CCNPP Corrective Action Program is used to take the necessary corrective actions. The Preventive Maintenance Program is discussed further in subsection Group 1 - Aging Management Programs, above.

Group 3 - (fatigue for PC rails) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to fatigue for the PC rails:

- The PC rails provide structural and/or functional support to the PC whose failure could directly prevent satisfactory accomplishment of safety-related functions. This function must be maintained under CLB design loading conditions.
- The PC rails are fabricated of carbon steel. Quench cracks at flame-cut holes in some sections of the PC rails result in areas of high stress concentration.
- Low-cycle fatigue is a plausible ARDM for the PC rails because they are subject to repeated loading and non-uniform distribution of stresses whenever the PC is used for lifting loads. If unmanaged, this ARDM could result in unstable crack growth under CLB design loading conditions such that the PC rails may not be able to perform their structural support function.
- Periodic inspection and NDE of the PC rails under the Preventive Maintenance Program will monitor the effectiveness of weld repairs, detect crack growth due to fatigue, document unsatisfactory conditions, and initiate appropriate corrective action.

Therefore, there is a reasonable assurance that the effects of aging will be adequately managed for the PC rails such that they will be capable of performing their intended function consistent with the CLB during the period of extended operation under all design loading conditions.

Group 4 - (fatigue, wear, and mechanical degradation/distortion for wire rope) - Materials and Environment

The construction materials for hoisting ropes and drive cables for the FHE and HLHC are listed in Table 3.2-1. [Reference 2, Attachment 3] Stainless steel is used for wire rope that routinely comes in contact with borated water in the SFP and refueling pools. [References 6, 11, 12, 14, 49, 50, and 51] Improved plow steel, a high-quality, high-strength carbon steel, is used to fabricate the hoisting ropes for the SFCHC main hoist and ISSGC. [References 10 and 14] Alloy steel is specified for the PC hoisting ropes. [Reference 10] When not submerged in the SFP and refueling pools, wire rope is exposed to the external environments discussed in subsection Group 1 - Materials and Environment, above. [Reference 2, Attachment 6]

Group 4 - (fatigue, wear, and mechanical degradation/distortion for wire rope) - Aging Mechanism Effects

Fatigue is a common degradation of structural members produced by periodic or cyclic loadings. Two types of fatigue exist for structural components such as wire rope. Low-cycle fatigue involves a low frequency of high-level, repeated loads. The number of cycles is usually less than 10^5 for steel structures. [Reference 18, Attachment 1] High-cycle fatigue occurs when the component cyclical stresses (including modifying factors such as stress concentrations and surface conditions) exceed the material fatigue strength for the number of cycles. Fatigue damage results in cracking and breakage of individual wires and strands that comprise the rope. Wire rope operating over sheaves and drums is subjected to cyclic bending stresses. In normal operation, wire rope is also subjected to vibration in the form of wave action characterized by either low-frequency or sharp, high-frequency cycles. The energy generated in the rope by the wave action must be absorbed at some point (e.g., the end attachment, the tangent where the rope contacts the sheave). [Reference 2, Attachment 5]

Wear results from relative motion between two surfaces and from the influence of hard, abrasive particles. The most common result of wear is loss of material from one or both surfaces involved in the contact. When bent over a sheave, a wire rope's load-induced stretch causes it to rub against the groove. Abrasive wear also occurs as individual wires and strands move within the wire rope itself while bent around the sheave or drum. [Reference 2, Attachment 5]

Mechanical degradation/distortion of wire rope results from mechanical abuse during normal operation by abnormal or accidental forces. Examples of abuses during normal operation include sudden release of tension, rolling over sharp objects, layer-to-layer crushing resulting from improper drum winding, torsional imbalances caused by sudden stops, and continuous pounding against other objects. [Reference 2, Attachment 5]

Fatigue, wear, and mechanical degradation/distortion are all considered plausible for wire rope associated with FHE and HLHC. All of these mechanisms result in a loss of load-carrying capacity. If unmanaged, the wire rope and the associated FHE and HLHC could lose their ability to perform their intended functions under the CLB design loading conditions. [Reference 2, Attachment 6]

Group 4 - (fatigue, wear, and mechanical degradation/distortion for wire rope) - Methods to Manage Aging

Mitigation: The effects of fatigue, wear, and mechanical degradation/distortion can be mitigated by proper component design and material selection, and by operational practices that reduce the number and severity of mechanical abuses on wire rope associated with the FHE and HLHC.

Discovery: The effects of fatigue, wear, and mechanical degradation/distortion on wire rope are detectable by visual inspection. The physical appearance of the outer surfaces of a wire rope is a good indicator of its condition. A visual examination by a person familiar with hoisting ropes and drive cables can be used to identify gross damage and evidence of operational abuse. Under normal operation and in the absence of corrosion and rope distortion, the extent to which wire surfaces are worn and the number and location of broken wires can be used to estimate the remaining rope strength. Evaluation of any observed damage by a trained inspector can determine whether continued use or replacement is appropriate. [Reference 52, page 62]

Group 4 - (fatigue, wear, and mechanical degradation/distortion for wire rope) - Aging Management Program(s)

Mitigation: There are no programs credited with mitigating the effects of these ARDMs for wire rope.

Discovery: Periodic inspection of wire rope associated with the FHE and HLHC for the effects of fatigue, wear, and mechanical degradation/distortion is controlled through a combination of existing operations inspections and maintenance programs. [Reference 2, Attachment 8]

- The Calvert Cliffs Operating Manual and the Performance Evaluation Program are described in subsection Group 1 - Aging Management Programs, above. In accordance with OI-25E, "Fuel Transfer System," the hoisting ropes and drive cables for the fuel upending machines and transfer carriages are visually inspected for damage if the equipment has been secured for greater than 60 days, if a refueling campaign (i.e., defuel/refuel or fuel shuffle) is imminent, or as designated following maintenance. [Reference 53] The Performance Evaluation Program provides for wire rope inspection for the SFHM, RRM, the spent fuel inspection elevator, and the new fuel elevator prior to refueling campaigns. The checks for the SFHM and the elevators are also performed every 90 days. [References 22, 23, and 54] Calvert Cliffs procedure PE 0-81-1-O-Q directs performance of checks in accordance with OI-25A, which requires visual inspection of the hoisting rope while running the hoist through the full length of travel. [Reference 24] PE 0-81-2-O-C directs performance of checks in accordance with OI-25C, which requires the same activities for the main hoist on each unit's RRM. [Reference 25] Visual inspection for damage to hoisting ropes in accordance with OI-25B, "Fuel Elevators," is directed by PE 0-81-3-O-Q for the spent fuel inspection elevator and the new fuel elevator. [Reference 55]
- Calvert Cliffs procedure MN-1-104 is described in subsection Group 1 - Aging Management Programs, above. The wire rope inspections specified in this procedure and implemented through the Preventive Maintenance Program (below) require visual observation for gross damage (e.g., kinking, crushing, unstranding, and birdcaging; general corrosion; dryness of lubricant; scrubbing; evidence of heat damage; broken or cut wires). [Reference 26, Section 5.8.E.3]

Prior to initial use of the Transfer Machine Jib Crane to handle heavy loads (e.g., the fuel transfer carriage), a wire rope inspection is required as part of the testing and inspection discussed in subsection Group 1 - Aging Management Programs, above. [Reference 26, Sections 5.7.A.3 and 5.8.F]

- The CCNPP Preventive Maintenance Program is described in subsection Group 1 - Aging Management Programs, above. The following Preventive Maintenance Tasks implement the requirements of MN-1-104 by directing visual inspections of hoisting ropes and/or drive cables for the listed FHE and HLHC components:

10812007, 20812009	for the Unit 1, Unit 2 Fuel Upending Machines and Transfer Carriages [Reference 56]
10812013, 20812014	for the Unit 1, Unit 2 RRM main hoists [Reference 57]
10992016, 20992010	for the Unit 1, Unit 2 RRM auxiliary hoists [Reference 58]
00992009	for the SFCHC [References 30 and 31]
10992010, 20992002	for Unit 1, Unit 2 PCs [References 32 and 33]
10992007	for the ISSGC [References 34 and 35]

When damage is discovered, a more detailed inspection is made, applying quantitative criteria from industry standards for evaluation of wire rope condition. Continued use or replacement of damaged wire rope is determined by a person qualified as Load Handling Engineer in accordance with MN-1-104.

Group 4 - (fatigue, wear, and mechanical degradation/distortion for wire rope) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to fatigue, wear, and mechanical degradation/distortion for wire rope associated with the FHE and HLHC:

- Wire rope, used to fabricate hoisting ropes and drive cables, provides structural and/or functional support for the associated FHE and HLHC. Failure of wire rope could directly prevent satisfactory accomplishment of safety-related functions that must be maintained under CLB design loading conditions.
- The construction materials for wire rope include stainless steel, improved plow steel, and alloy steel.
- Fatigue and wear are plausible ARDMs for wire rope when used in load handling applications. Mechanical degradation/distortion is plausible because of abnormal or accidental forces that may be applied during normal operation. If unmanaged, these ARDMs could result in a loss of load-carrying capacity such that the wire rope may not be able to perform its structural support function under CLB design loading conditions.
- Visual inspection of wire rope under the Calvert Cliffs Operating Manual, the Performance Evaluation Program, the load handling procedure, and the Preventive Maintenance Program, as applicable, evaluates the condition of hoisting ropes and drive cables for FHE and HLHC, documents unsatisfactory conditions, and initiates appropriate corrective action.

Therefore, there is a reasonable assurance that the effects of aging will be adequately managed for wire rope associated with the FHE and HLHC such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation under all design loading conditions.

3.2.3 Conclusion

The aging management programs discussed for the FHE and HLHC are listed in Table 3.2-2. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects in such a way that the intended functions of the components of the FHE and HLHC will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

Table 3.2-2

AGING MANAGEMENT PROGRAMS FOR THE FHE AND HLHC SYSTEM

	Program	Credited As
Existing	Operations Section Performance Evaluations and associated Operating Instructions • PE 0-81-1-O-Q and OI-25A, "Spent Fuel Handling Machine" (procedure) • PE 0-81-2-O-C and OI-25C, "Refueling Machine" (procedure)	Program for discovery and management of general corrosion/oxidation effects in carbon steel parts of the SFHM, RRM, and associated components by performing periodic visual inspections. (Group 1)
Existing	Load Handling Procedure, MN-1-104	Program for discovery and management of general corrosion/oxidation effects in carbon steel parts of FHE and HLHC components by performing visual inspections. (Group 1) Program for discovery and management of fatigue, wear, and mechanical degradation/distortion effects in wire rope by performing visual inspections. (Group 4)
Existing	Preventive Maintenance Tasks 10992001 (20992000), "Perform NDE on Polar Crane Rails"	Program for discovery and management of fatigue effects in carbon steel PC rails by performing NDE. (Group 3)
Existing	Operating Instructions and Operations Section Performance Evaluations, as applicable • OI-25A and PE 0-81-1-O-Q, "Spent Fuel Handling Machine" (procedure) • OI-25B and PE 0-81-3-O-Q, "Fuel Elevators" (procedure) • OI-25C and PE 0-81-2-O-C, "Refueling Machine" (procedure) • OI-25E, "Fuel Transfer System" (procedure)	Program for discovery and management of fatigue, wear, and mechanical degradation/distortion effects in wire rope for SFHM, spent fuel inspection and new fuel elevators, RRM main hoists, and the Fuel Upending Machines and Transfer Carriages, respectively, by performing periodic visual inspections. (Group 4)

Table 3.2-2

AGING MANAGEMENT PROGRAMS FOR THE FHE AND HLHC SYSTEM

	Program	Credited As
Existing	Preventive Maintenance Tasks: • 10812007 (20812009), "Inspect and Lubricate Fuel Transfer Cables, Winches, and Drivers" • 10812013 (20812014), "Perform NDE on Fuel Handling Machine Crane Hook" • 10992016 (20992010), "Perform NDE on 45', 69' Containment and Refueling Machine Crane Hooks" • 00992009, "Inspect Auxiliary Building Cask Handling Crane" • 10992010 (20992002), "Lubricate Containment Polar Cranes" • 10992007, "Inspect Intake Structure Gantry Crane"	Program for discovery and management of fatigue, wear, and mechanical degradation/ distortion effects in wire rope for the Fuel Upending Machines and Transfer Carriages, RRM main hoists, RRM auxiliary hoists, SFCHC, PCs, and ISSGC, respectively, by performing visual inspections. (Group 4)
Modified	Preventive Maintenance Tasks (modified to explicitly present inspection requirements): • 00992009, "Inspect Auxiliary Building Cask Handling Crane" • 10992010 (20992002), "Lubricate Containment Polar Cranes" • 10992007, "Inspect Intake Structure Gantry Crane" • 10642031 (20642030), "Perform Surface Examination on Head Lift Rig"	Program for discovery and management of general corrosion/oxidation effects in carbon steel parts of the SFCHC, PC, ISSGC, and RV head lift rig, respectively, by performing visual inspections. (Group 1)
Modified	BACI Program, MN-3-301	Program for discovery and management of general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members by performing visual inspections. (Group 2)

3.2.4 References

1. CCNPP IPA Methodology, Revision 1
2. CCNPP Life Cycle Management Aging Management Review Report, "Fuel Handling Equipment (FHE) and Other Heavy Load Handling Cranes (HLHC) Commodity Evaluation," Revision 1
3. CCNPP Updated Final Safety Analysis Report, Units 1 and 2, Revision 20
4. CCNPP Life Cycle Management System and Structure Screening Results, Revision 4
5. Bechtel Specification No. 6750-C-30, "Specification for New Fuel Inspection Platform - CCNPP Units 1 and 2," Revision 1
6. Bechtel Specification No. 6750-M-390, "Specification for Fuel Pool Service Platform, New Fuel Elevator, Spent Fuel Inspection Device and Spent Fuel Storage Racks - CCNPP Units 1 and 2," Revision 8
7. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 2
8. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0
9. Bechtel Specification No. 6750-C-19, "Specification for Furnishing, Detailing, Fabricating, Delivering, and Erecting Structural Steel - CCNPP Units 1 and 2," Revision 3
10. Bechtel Specification No. 6750-C-42, "Specification for Overhead Traveling Cranes - CCNPP Units 1 and 2," Revision 5
11. Combustion Engineering Specification No. 8067-PE-801, "Project Engineering Specification for Reactor Refueling Machine," Revision 2
12. CCNPP Specification No. SP-551, "Specification for a Replacement Spent Fuel Pool Service Platform," Revision 4
13. Bechtel Specification No. 6750-C-31, "Specification for Furnishing, Detailing, Fabricating, Painting, and Delivering Containment and Auxiliary Building Structural Steel - CCNPP Units 1 and 2," Revision 3
14. CCNPP Specification No. SP-601, "Modification of Spent Fuel Cask Crane," Revision 4
15. Bechtel Specification No. 6750-M-395, "Specification for Miscellaneous Hoists and Monorails - CCNPP Units 1 and 2," Revision 2
16. BGE Drawing 12017-0049, "Closure Head Lifting Rig and Cooling Duct Assembly," Revision 7
17. BGE Drawing 12017-0057, "Closure Head Lifting Rig and Cooling Duct Assembly," Revision 3
18. CCNPP Administrative Procedure EN-1-305, "Component Aging Management Review for Structures," Revision 1
19. CCNPP Administrative Procedure NO-1-201, "Calvert Cliffs Operating Manual," Revision 7
20. CCNPP Administrative Procedure NO-1-203, "Operations Section Performance Evaluations," Revision 3

21. CCNPP Administrative Procedure NO-1-100, “Conduct of Operations,” Revision 9

22. CCNPP Operations Performance Evaluation Requirements Routine No. 0-81-1-O-Q, “Spent Fuel Handling Machine,” Revision 1

23. CCNPP Operations Performance Evaluation Requirements Routine No. 0-81-2-O-C, “Refueling Machine,” Revision 1

24. CCNPP Operating Instructions, OI-25A, “Spent Fuel Handling Machine,” Revision 15

25. CCNPP Operating Instructions, OI-25C, “Refueling Machine,” Revision 15

26. CCNPP Administrative Procedure MN-1-104, “Load Handling,” Revision 5

27. Letter from Mr. R. A. Clark (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated May 27, 1983, “Safety Evaluation, Control of Heavy Loads -- Phase 1”

28. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. D. G. Eisenhut (NRC), dated March 1, 1982, "Control of Heavy Loads"

29. CCNPP Administrative Procedure MN-1-102, “Preventive Maintenance Program,” Revision 5

30. CCNPP NUCLEIS Database Repetitive Task 00992009, "Inspect Auxiliary Building Cask Handling Crane"

31. CCNPP Maintenance Procedure HE-19, "116/15 Ton Spent Fuel Cask Handling Crane Annual Inspection," Revision 5

32. CCNPP NUCLEIS Database Repetitive Tasks 10992010 (20992002), "Lubricate Containment Polar Cranes "

33. CCNPP Maintenance Procedure HE-05, "180/25 Ton Polar Crane Periodic Inspection," Revision 5

34. CCNPP NUCLEIS Database Repetitive Task 10992007, "Inspect Intake Structure Gantry Crane"

35. CCNPP Maintenance Procedure HE-20, "35/10 Ton Intake Structure Crane Annual Inspection," Revision 4

36. CCNPP NUCLEIS Database Repetitive Tasks 10642031 (20642030), "Perform Surface Examination on Head Lift Rig"

37. Letter from Mr. A. R. Blough (NRC) to Mr. R. E. Denton (BGE), dated May 6, 1993, “NRC Region I Resident Inspection Report Nos. 50-317/93-10 and 50-318/93-10 (March 14, 1993 - April 24, 1993)”

38. CCNPP Procedure MN-3-301, “CCNPP Boric Acid Corrosion Inspection Program,” Revision 1 Change 0

39. CCNPP Procedure MN-3-110, “Inservice Inspection of ASME Section XI Components,” Revision 2

40. BGE “Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant,” Revision 48

41. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 29, 1994, "Licensee Event Report 94-004, Revision 1, Excessive Corrosion of Incore Instrumentation Flange Components"

42. BGE Drawing 61746, "Containment Interior Crane Girder Plan & Details," Revision 3

43. CCNPP Life Cycle Management Aging Management Review Report, "Containment Structure (System 059)," Revision 4

44. BGE Drawing 12324-0010, "Crane Rail & Accessories," Revision 1

45. BGE Drawing FSK-C-0502, "U-2 Polar Crane Bridge Rail Field-Welded Joints & Repairs," Revision 5

46. CCNPP Engineering Service Package ES199701207, "Evaluate Cracks on Unit 2 Polar Crane Rail," June 13, 1997

47. CCNPP Maintenance Procedure HE-18, "Polar Crane Rail Inspection," Revision 2

48. CCNPP NUCLEIS Database Repetitive Tasks 10992001 (20992000), "Perform NDE on Polar Crane Rails"

49. Combustion Engineering Specification No. 8067-PE-800, "General Engineering Specification for Reactor Servicing Equipment," Revision 8

50. Combustion Engineering Specification No. 8067-PE-802, "Project Engineering Specification for Fuel Transfer System," Revision 1

51. BGE Drawing 12804-0028, "6-Ton Jib Crane for Transfer Assembly," Revision 3

52. North American Crane Bureau, Inc., "Overhead Crane Inspector Training" (student workbook), 1997

53. CCNPP Operating Instructions, OI-25E, "Fuel Transfer System," Revision 10

54. CCNPP Operations Performance Evaluation Requirements Routine No. 0-81-3-O-Q, "Fuel Elevators," Revision 0

55. CCNPP Operating Instructions, OI-25B, "Fuel Elevators," Revision 7

56. CCNPP NUCLEIS Database Repetitive Tasks 10812007 (20812009), "Inspect and Lubricate Fuel Transfer Cables, Winches, and Drivers"

57. CCNPP NUCLEIS Database Repetitive Tasks 10812013 (20812014), "Perform NDE on Fuel Handling Machine Crane Hook"

58. CCNPP NUCLEIS Database Repetitive Tasks 10992016 (20992010), "Perform NDE on 45', 69' Containment and Refueling Machine Crane Hooks"

3.3A Primary Containment Structure

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Primary Containment. The Primary Containment was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared concurrently and will, collectively, comprise the BGE LRA.

3.3A.1 Scoping

The IPA Methodology system level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. The Primary Containment consists of two categories of components, the Containment Structure and the Containment System. The Containment Structure includes the majority of structural components such as beams, columns, walls, and liners. The Containment System includes penetrations, hatches, air locks, and associated instrumentation.

For the Containment Structure, the component level scoping to determine which components are within the scope of license renewal was accomplished utilizing the scoping process for structures as described in Section 4.2 of the BGE IPA Methodology. This was done because the features and documentation of structures are distinct from that of systems at CCNPP, and therefore, the component level scoping process for structures differs from that applied to systems. In the structural component scoping process, scoping is conducted using a generic listing of structural component types. Additional structural component types not included in the generic listing because they are unique to the Containment Structure are also identified. Scoping is implemented by determining which structural component types are required for performance of the passive intended functions of the structure. The results of the Containment Structure scoping are merged with the results of the Containment System scoping to present a combined scoping result for Primary Containment.

For the Containment System, the component level scoping to determine which components are within the scope of license renewal was accomplished utilizing the scoping process for systems as described in Section 4.1 of the BGE IPA Methodology. This scoping step begins with a listing of passive intended functions. Subsequently, component types are dispostioned as either only associated with active functions, subject to replacement, or subject to AMR either in this section of the BGE LRA or another section. The component level scoping includes a determination of which components are subject to aging management review (AMR).

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

Section 3.3A.1.1 presents the results of the structure/system level scoping, 3.3A.1.2 the results of the component level scoping, and 3.3A.1.3 the results of scoping to determine components subject to an AMR.

3.3A.1.1 System Level Scoping

This section begins with a description of the Containment Structure and Containment System, which includes the boundaries of the Primary Containment as it was scoped. A brief summary is presented of the overall operating experience related to aging. Finally, the results of the system level scoping process are presented with a listing of intended functions of Primary Containment.

Description/Conceptual Boundaries

Figure 3.3A-1 is a simplified layout of site structures showing the structures that are within the scope of license renewal. The CCNPP site arrangement consists of numerous structures that are shown on Updated Final Safety Analysis Report (UFSAR) Figures 1-2 through 1-30, with further discussion of their design features in Chapter 5. [Reference 1, Chapters 1 and 5; References 2, 3, and 4] A general description, boundary, and design discussion of the Containment Structures and Containment System follows: [Reference 1, Chapters 1, 5 and 8]

The twin Containment Structures are located northwest and southwest of the Auxiliary Building with a connective boundary to the Auxiliary Building formed by the cylindrical shape of each Containment Structure. Each Containment Structure houses a reactor and other Nuclear Steam Supply System components consisting of steam generators, reactor coolant pumps, a pressurizer, and some of the reactor auxiliaries that do not normally require access during power operation. The containment consists of a shallow domed roof and a reinforced concrete cylinder that rests on a reinforced concrete foundation slab. The concrete cylinder and dome incorporate a post-tensioned contraction design. A carbon steel liner is attached to the inside of the Containment Structure to assure a high degree of leak tightness. There are three personnel and equipment access openings in the containment: a two-door personnel air lock, a large diameter single door equipment hatch, and a two-door personnel escape hatch. The primary containment has numerous penetrations for piping and electrical connections. These penetrations are pressure-resistant, leak-tight assemblies, which are welded to the containment liner. A fuel transfer tube penetration in the containment is provided to permit fuel movement between the refueling pool in the containment and the spent fuel pool in the Auxiliary Building. A normal and an emergency sump are provided in the containment floor. [Reference 1, Section 1.2.5; Reference 5, Section 1-1]

The Containment Structure and its structural components provide structural/functional support and shelter/protection to safety-related (SR) and non-safety-related equipment inside the Containment Structure. The Containment Structure also serves as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of postulated Design Basis Events (DBEs). In addition, the Containment Structure provides a missile, flood, and fire barrier for SR equipment. The boundary addressed by this scoping and evaluation includes all in-containment structural components serving such functions and components comprising the containment pressure boundary, but does not include commodity items such as pipe supports and snubbers. [Reference 5, Section 1.1.2]

The Containment Structure is designed to withstand an internal pressure of 50 psig, a coincident concrete surface temperature of 276°F, and limit leakage to no more than 0.20% by weight per day at the design temperature and pressure. The Containment Structure is designated a seismic Category I structure and is designed for all loading combinations described in Section 5A.3 of the UFSAR. [Reference 1, Sections 1.2.5 and 5.1.1]

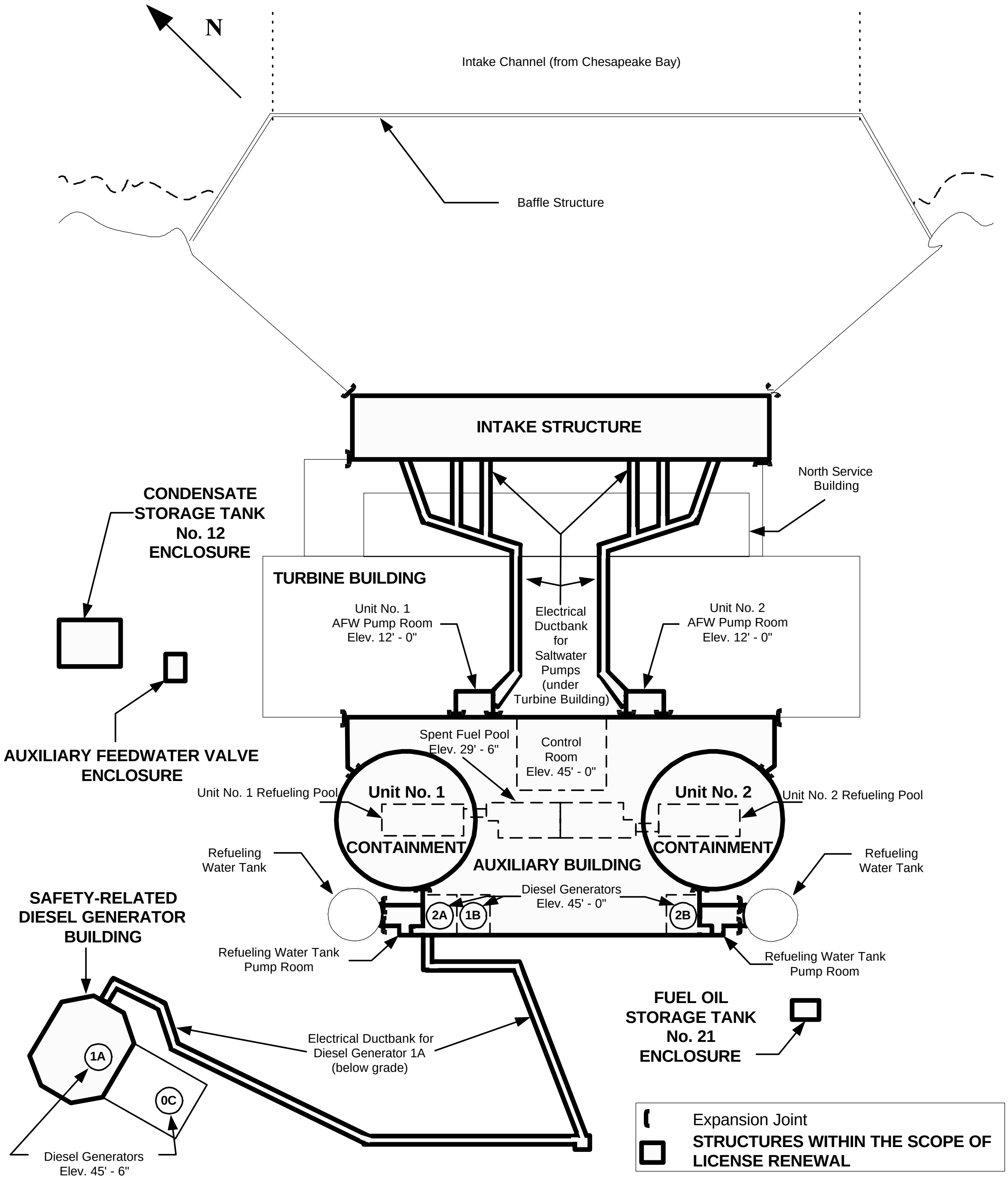

Figure 3.3A-1 Simplified Layout of Structures

The Containment System includes those components of the primary Containment Structure that are listed in the CCNPP equipment list as individual components with unique equipment identifiers. Components within the Containment System boundary include the following major component types: Penetration, Door, Pressure Indicator, Pressure Switch, and Position Switch. The Containment System is in scope for license renewal based on 10 CFR 54.4(a) criteria. The Containment System components perform one or more of the following functions: provide closure on containment air lock and access/egress hatches, maintain functionality of electrical components as addressed by the Environmental Qualification (EQ) Program, and maintain the pressure boundary for the system. [Reference 6, Sections 1.1.2 and 1.1.3]

Containment penetrations range in size from the small closure pieces for electrical and piping penetrations to larger components such as air locks and the equipment hatch. All containment penetrations are pressure resistant, leak-tight, welded assemblies designed, fabricated and tested in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Class B, Nuclear Vessel Code. [Reference 1, Section 5.1.4.4]

The conceptual boundaries of this evaluation include the Containment Structure and all of its structural components such as foundations, walls, slabs, and steel beams. Component supports that are connected to the structural components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. Component supports are defined as the connection between a system, or component within a system, and a plant structural member. An example of a component support is the fixed base that supports a pump. The pump would be scoped with its respective system evaluation. The component support is the fixed base that connects the concrete equipment pad to the pump. The fixed base is scoped with the Component Supports Commodity Evaluation and the concrete equipment pad is scoped with the evaluation for the structure. If anchor bolts are used, there is overlap between the Component Supports Commodity Evaluation and the evaluation for the structural component. Evaluations for structural components consider the effects of aging caused by the surrounding environment, while the Component Supports Commodity Evaluation considered the effects of aging caused by the supported equipment (thermal expansion, rotating equipment, etc.) as well as the surrounding environment. Supports for structural components such as platform hangers are not "component supports" in this sense because any support for a structural component is itself a structural component and is included in the scope of its respective structure. [Reference 7, Section 1.1.1]

Cranes and fuel handling equipment that are connected to structures are evaluated for the effects of aging in the Fuel Handling Equipment and Other Heavy Load Handling Cranes Commodity Evaluation in Section 3.2 of the BGE LRA. The polar crane, reactor vessel head lift rig, transfer machine jib crane, fuel upending machine, and reactor refueling machine were evaluated in the Cranes and Fuel Handling Commodity Evaluation and are not included in this section. The polar crane girders are included herein.

Operating Experience

An inspection of the Unit 1 Primary Containment was performed in 1992 to support the license renewal screening and AMR activities for the structures at CCNPP. The inspection was to evaluate the overall condition of the Primary Containment. A representative sample of internal and external structural components were examined, to the extent practical, in accordance with industry standards. The methodology employed meets the intent of the industry standard, "Rules for Inservice Inspection, Section XI, ASME Boiler and Pressure Vessel Code," which gives rules for the inspection of concrete. Under these rules, the exterior and interior surfaces of the Containment Structure and components in the Containment System were found to be in good to excellent condition. The responsible engineer determined by visual examination that there is no evidence of damage or degradation sufficient to warrant further evaluation or repair.

In 1997, during performance of the 20-year Technical Specification tendon surveillance on Unit 1 Containment Structure, broken wires were discovered. The discovery of broken wires initiated an expansion of the vertical tendon inspection scope to perform visual inspection and lift-off testing on all vertical tendons for Unit 1. At the completion of the expanded scope, a number of tendons were identified as having severe corrosion (pitting greater than 0.003 inches) and/or broken wires. A root cause analysis concluded that tendon wire failures and corrosion problems resulted from a combination of water and moist air intrusion, and inadequate initial grease coverage of wires below the upper stressing washer. This combination created a corrosive environment, which in turn, caused wire failure either by general corrosion or by hydrogen-induced cracking. [References 8 and 9] Further details on tendon corrosion and other operating experience is provided in the Group discussions, where appropriate.

System/Structure Scoping Results

The Containment Structure and the Containment System were both determined to be within the scope of license renewal based on 10 CFR 54.4(a) as a result of executing the screening process described in Section 3 of the BGE IPA Methodology. The following intended functions of the Primary Containment were determined based on the requirements of §54.4(a)(1) and (2): [References 5, 6, 10, and 11]

1. Support a pressure boundary or a fission product retention barrier function to protect public health and safety in the event of any postulated DBEs;
2. Provide shelter/protection to SR equipment (this function includes radiation protection for EQ equipment and high energy line break-related protection equipment);
3. Provide structural and/or functional support to SR equipment;
4. Serve as a missile barrier (internal or external);
5. Provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions; and
6. Provide flood protection barrier (internal flood event).

The following intended functions of the Containment Structure and Containment System were determined based on the requirements of §54.4(a)(3): [References 5, 6, 10, and 11]

7. Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant;
8. Provide closure of containment air lock and access/egress hatches during a station blackout (active); and
9. Maintain the functionality of electrical components as addressed by the EQ program.

3.3A.1.2 Component Level Scoping

During the scoping process, a list of generic structural component types were identified for the Containment Structure. Additional structural component types, not included in the generic listing because they are unique to the Containment Structure, were also identified. Each structural component type is a category of components that is comprised of one or more structural components based on design and function. A total of 34 structural component types were identified as within the scope of license renewal because they contribute to at least one of the intended functions of the Containment Structure. All of these structural component types are addressed below in Section 3.3A.1.3. These structural component types were further combined into the following four structural component categories based on their design and materials. [References 5 and 10]

- Concrete Components;
- Structural Steel Components;
- Architectural Components; and
- Unique Components (e.g., post-tensioning system, containment liner, refueling pool liner and permanent cavity seal ring, and emergency sump cover and screen).

The components comprising the Containment System were identified through the CCNPP equipment database. The purpose of the component level scoping was to identify all system components that support one or more of the intended functions of the system. The intended functions of the Containment System are Functions 1, 3, 8, and 9 as listed above in section 3.3A.1.1. Components that support these intended functions were categorized into the following three component types: [References 6 and 11]

Component Type	Component Description
DOOR	Air locks and equipment hatch
PEN	Containment penetrations and fuel transfer tube
ZS	Limit switches

Some components in the Containment System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 6, Section 3.2]

- Structural supports for piping, cables, and most components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. Supports for the steam generators and pressurizer are evaluated in the Reactor Coolant System evaluation in Section 4.1 of the BGE LRA. Supports for the reactor vessel are evaluated in the Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System in Section 4.2 of the BGE LRA.
- Electrical control and power cabling are evaluated for the effects of aging in the Cables Evaluation in Section 6.1 of the BGE LRA.

3.3A.1.3 Components Subject to AMR

This section contains a discussion of structural component types for the Containment Structure and Containment System that are subject to AMR. In accordance with Section 5.0 of the BGE IPA Methodology, components that support only active functions, or that are subject to periodic replacement based on a qualified life or specified time period do not require AMR. Tables 3.3A-1 and 3.3A-2 includes the 44 component types for the Containment Structure and Containment System, respectively, and lists, by function number, the passive intended function(s) that each one supports. [References 6 and 11]

The intended functions of the Containment Structure are Functions 1 through 7 as listed above in Section 3.3A.1.1. All of these intended functions are passive. Additionally, none of the structural component types are subject to periodic replacement based on a qualified life or specified time period. Therefore, all of the Containment Structure components that comprise the 37 structural component types within the scope of license renewal require AMR. [Reference 5]

The intended functions of three of the seven Containment System component types, i.e., DOOR, PEN, and ZS, are Functions 1, 8, and 9 as listed above in Section 3.3A.1.1. Function 8, provide closure of containment air lock and access/egress hatches during a station blackout, is an active function performed manually by an operator. This active function is the only intended function for component type ZS, limit switches. Therefore, the component type ZS does not require AMR. [References 6 and 11]

The other component type that supports the active function is DOOR. The component type DOOR is comprised of the containment personnel air lock, the containment emergency air lock, and the containment equipment hatch. These components also have a passive intended function of the Containment System, so they require AMR.

The containment personnel and emergency air locks and the equipment hatch are installed with resilient gaskets to help assure a leak tight barrier for the Primary Containment Structure. The equipment hatch and personnel air lock gaskets are currently scheduled for replacement every four years and are, therefore, not subject to AMR. [References 12 and 13]

The emergency air lock gaskets are replaced based on condition. The gaskets are currently scheduled for inspection every two years. The inspection is performed visually and any indication of nicks, tears, or other damage is recorded. The door gasket is then measured to determine the amount of penetration, i.e., the gasket protrusion as measured from the door face minus the door-face-to-bulkhead gap. If the calculation results are unsatisfactory, the door mechanism is adjusted to account for the permanent set of the gasket. When the permanent set becomes excessive, the gasket is replaced. Specific guidance is provided to the tester to promote maximum sealing, prevent unnecessary wear, and avoid metal-to-metal contact. The final results are verified by plant supervision. [Reference 14]

The periodic inspections discussed above lead to replacement of the emergency air lock gaskets based on condition and provides reasonable assurance that the intended function of these gaskets will be maintained in the period of extended operation. These inspections are called for by the CCNPP Preventive maintenance Program.

The components that comprise the component type PEN are containment electrical penetrations, containment mechanical penetrations, containment fuel transfer tube/bellows, and containment sump recirculation penetrations. Each of these components have passive intended functions and require AMR. It should be noted that some of the electrical penetrations that are required to support the EQ intended function are partly addressed in Section 6.3, EQ, of the BGE LRA. General corrosion of these penetrations is addressed in this section of the LRA and radiation damage and thermal damage are addressed in the EQ section of the LRA.

TABLE 3.3A-1

CONTAINMENT STRUCTURE COMPONENT TYPES REQUIRING AMR

Component Type	Applicable Function
Concrete (Including Reinforcing Steel)	
Columns	3, 5
Beams	3, 5
Concrete Slabs and Equipment Pads	3, 5
Elevated Floor Slabs	3, 5
Cast-In-Place Anchors*	3, 5
Grout	3, 5
Sumps	3
Post-Installed Anchors*	3
Structural Steel	
Columns*	3, 5
Beams*	3, 5
Baseplates*	3, 5
Floor Framing*	3, 5
Bracing*	3, 5
Platform Hangers*	3, 5
Decking*	3, 5
Floor Grating*	3, 5
Checkered Plates*	3, 5
Stairs and Ladders*	5
Architectural Components	
Coatings (including galvanizing)	2
Partitions & Ceilings	7
Unique Components	
Basemat Liner	1
Containment Liner	1
Concrete Basemat	1, 2, 3, 4, 5, 6, 7
Concrete Dome	1, 2, 3, 4, 5, 7
Concrete Containment Wall	1, 2, 3, 4, 5, 6, 7
Primary Shield Wall	2, 3, 4
Secondary Shield Wall	2, 3, 4
Refueling Pool Concrete	3
Refueling Pool Liner	1
Refueling Pool Permanent Cavity Seal Ring (PCSR)	1
Removable Missile Shield	2, 4, 5
Post-Tensioning System	1, 2, 3, 4
Trisodium Phosphate (TSP) Baskets*	1, 2
Crane Girder*	5
Lubrite Plates*	3, 5
Pipe Whip Restraints*	2
Emergency Sump Cover and Screen*	2, 3

(#1-9) numbers correspond to the associated intended functions as listed in Section 3.3A.1.1

* indicates that the component type is included under the heading “Steel Components” in Table 3.3A-3

TABLE 3.3A-2

CONTAINMENT SYSTEM COMPONENT TYPES REQUIRING AMR

Component Type	Applicable Function
Device Type PEN	
Electrical Penetrations	1, 9
Mechanical Penetrations	1
Fuel Transfer Tube/Bellows	1
Emergency Sump Recirculation Penetration	1
Device Type DOOR	
Containment Personnel Air lock	1, 8
Containment Emergency Air lock	1, 8
Containment Equipment Hatch	1, 8

(#1-9) - numbers correspond to the associated intended functions as listed in Section 3.3A.1.

3.3A.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for Containment Structure and Containment System components is given in Tables 3.3A-3 and 3.3A-4, respectively, with plausible ARDMs identified by a check mark (✓) in the appropriate column. [Reference 5, Attachments 1 and 2; Reference 6, Table 4-2]

For efficiency in presenting the results of these evaluations, structural component type/ARDM combinations are grouped together where there are similar characteristics and the discussion is applicable to the structural components within that group. Exceptions are noted where appropriate. Table 3.3A-2 also identifies the group to which each structural component type/ARDM combination belongs. The following groups have been selected:

Group 1 - Corrosion of tendons/prestress losses;

Group 2 - Corrosion of steel;

Group 3 - Corrosion of the containment wall and dome liners;

Group 4 - Corrosion of the refueling pool liner and permanent cavity seal ring (PCSR); and

Group 5 - Weathering of grout.

TABLE 3.3A-3

CONTAINMENT STRUCTURE COMPONENTS POTENTIAL AND PLAUSIBLE ARDMs

Potential ARDMs	Concrete Columns	Concrete Beams	Concrete Slabs & Equipment Pads	Elevated Floor Slabs	Grout	Sumps	Steel * Components	Coatings	Post-Tensioning System	Partitions and Ceilings
Freeze-Thaw										
Leaching of Calcium Hydroxide										
Aggressive Chemicals										
Corrosion of Embedded Steel/Rebar										
Shrinkage										
Settlement										
Corrosion of Steel							✓(2)			
Corrosion of Liner and PCSR										
Corrosion of Tendons									✓(1)	
Prestressing Losses									✓(1)	
Weathering					(5)					
Elevated Temperature										
Irradiation										
Fatigue										

Potential ARDMs	Concrete Dome	Concrete Containment Wall	Concrete Basemat	Containment Liner	Basemat Liner	Refueling Pool Liner and PCSR	Refueling Pool Concrete	Primary Shield Wall	Secondary Shield Walls	Removable Missile Shield
Freeze-Thaw										
Leaching of Calcium Hydroxide										
Aggressive Chemicals										
Corrosion of Embedded Steel/Rebar										
Shrinkage										
Settlement										
Corrosion of Steel										
Corrosion of Liner				✓(3)		✓(4)				
Corrosion of Tendons										
Prestress Losses										
Weathering										
Elevated Temperature										
Irradiation										
Fatigue										

* Includes all items marked with an asterisk (*) in Table 3.3A-1

✓ Indicates that the ARDM is plausible for structural and system components

(#) Indicates the Group in which this component type/ARDM combination is evaluated

TABLE 3.3A-4

CONTAINMENT SYSTEM COMPONENTS POTENTIAL AND PLAUSIBLE ARDMs

Potential ARDMs	Electrical Penetrations (non-EQ)	Mechanical Penetrations	Fuel Transfer Tube/Bellows	Containment Sump Recirculation Penetration	Containment Personnel Air lock	Containment Emergency Air lock	Containment Equipment Hatch
General corrosion/oxidation	✓(2)	✓(2)			✓(2)	✓(2)	✓(2)
Pitting/Crevice Corrosion							
Irradiation-Assisted Stress Corrosion Cracking							
Stress Corrosion Cracking/Intergranular Stress Corrosion Cracking (IGSCC) /Intergranular Attack							
Microbiologically Induced Corrosion							
Thermal Aging							
Hydrogen Damage							
Low Cycle Fatigue							
Stress Relaxation							

✓ Indicates that the ARDM is plausible for structural and system components

(#) Indicates the Group in which this component type/ARDM combination is evaluated

Settlement

Industry technical reports conclude that settlement is a potentially significant ARDM for pressurized water reactor Containment Structures at some plants. [Reference 15, Section 5.5] Settlement occurs both during construction and after construction. The amount of settlement depends on the physical properties of the foundation material. [Reference 5, Appendix J] Excavation unloading and structural loading during construction caused a small change in the void ratio of undisturbed soil. This change results in a very small or negligible amount of time-dependent settlement. [Reference 1, Section 2.7.6.2; Reference 5, Appendix J, Section 1.0] Compacted soil is subject to some degree of settlement in the first several months after construction. [Reference 15, Section 4.5.3.1] Settlement directly related to construction work is readily evident early in the life of the structure and is not considered to be an ARDM. Settlement may occur during the design life of the structure from changes in environmental conditions, such as lowering of the groundwater table. Sites with soft soil and/or sites with significant changes in underground water conditions over a long period of time may be susceptible to significant settlement. [Reference 15, Section 4.5.3.2] Concrete and steel structural members can be affected by differential settlement between supporting foundations, within a building, or between buildings. Severe settlement can cause misalignment of equipment and lead to overstress conditions within the structure. When buildings experience significant settlement, cracks in structural members, differential elevations of supporting members bridging between buildings, or both may be visibly detected. [Reference 5, Appendix J, Section 1.0] At CCNPP, long-term settlement was determined to be not plausible for the Containment Structure based on the following site-specific justification:

- The basemats for the Containment Structures are situated primarily on the site's Miocene deposit, which is an exceptionally dense soil that is capable of supporting loads on the order of 15,000 to 20,000 pounds per square foot (psf). [Reference 1, Section 2.7.3; Reference 5, Appendix J] The ultimate bearing capacity of the foundation strata is in excess of 80,000 psf, and the allowable bearing capacity is in excess of 15,000 psf. [Reference 1, Section 2.7.6.2] The design bearing pressure of the basemat for the Containment Structure is 8,000 psf, which is about the same as the removed overburden due to excavation. [Reference 5, Appendix J, Section 2.1]

- A permanent pipe drain system surrounding the plant is designed to maintain the groundwater table below Elevation 10'-0", which minimizes the fluctuation of the groundwater table, thus providing stable geological conditions around the Containment Structure. Stable geological conditions minimize the susceptibility of the Containment Structure to settlement. [Reference 5, Appendix J, Section 2.5]. The basemat for the Containment Structure is located between 1½- and 28-feet below the groundwater table. [Reference 1, Section 2.7.3.2; Reference 1, Figure 5-3]

- The basemat for the Containment Structure tends to uniformly settle as a rigid body. Most of the predicted ½-inch settlement is in terms of uniform settlement, which has no adverse effect on structural components of the Containment Structure. Any differential settlement is expected to be small and have negligible effect. [Reference 5, Appendix J, Section 2.4]

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

Group 1 - corrosion of tendons/prestress losses - Materials and Environment

Corrosion of tendons and prestress losses are two separate ARDMs grouped together because they both affect the containment Post-Tensioning System. The Post-Tensioning System is designed to contain a total of 876 tendons, including 204 dome tendons, 468 hoop tendons, and 204 vertical tendons. Each tendon was designed to contain ninety ¼-inch-diameter steel wires (American Society for Testing and Materials [ASTM] A-421-65T), two anchor heads, and two sets of shims. Each tendon is stressed to 80% of ultimate strength during installation and performs at approximately 50 to 60% of ultimate strength during the life of the structure. The tendon sheathing system consists of spiral wound carbon steel tubing connecting to a trumplate (bearing plate and trumpet) at each end. The sheath was installed for the initial construction concrete pour and does not provide an intended function. The bearing plates were fabricated from steel plate conforming with ASTM A6-66 and the trumpets from American Iron and Steel Institute (AISI) C1010-C1020 material. After fabrication, the tendon was shop dipped in a corrosion protection material, bagged, and shipped. After installation, the tendon sheathing was filled with a corrosion preventive grease providing the tendon with a grease environment for protecting the sheathing from a corrosive environment. The ends of all tendons are covered with grease-filled caps for corrosion protection. [Reference 1, Section 5.1.2.1; Reference 5, Appendices M and N, Sections 2.4]

Group 1 - corrosion of tendons/prestress losses - Aging Mechanism Effects

Corrosion of Tendons - When corrosion of prestressing tendons occurs, it is generally in the form of localized corrosion. Most corrosion-related failures of prestressing tendons have been attributed to pitting, stress corrosion, hydrogen embrittlement, or some combination of these. [Reference 5, Attachment M, Section 1.0]

Pitting is a highly localized form of corrosion. The primary parameter affecting its occurrence and rate is the environment surrounding the metal. The presence of halide ions, particularly chloride ions, is associated with pitting corrosion. [Reference 5, Attachment M, Section 1.0]

Stress corrosion cracking results from the simultaneous presence of a conducive environment, a susceptible material, and tensile stress. The environmental factors known to contribute to stress corrosion cracking in carbon steels are hydrogen sulfide, ammonia, and nitrate solutions. Prestressed tendon anchor heads, which are constructed of a high strength, low alloy steel bolting material, are vulnerable to stress corrosion cracking. [Reference 5, Attachment M, Section 1.0]

Hydrogen embrittlement occurs when hydrogen atoms, produced by corrosion or excessive cathodic protection potential, enter the metal lattice. Hydrogen produced by corrosion is not usually sufficient to result in hydrogen embrittlement of carbon steel. Cathodic polarization is the usual method by which this hydrogen is produced. The interaction between the dissolved hydrogen atoms and the metal atoms results in a loss of ductility manifested as brittle fracture. [Reference 5, Attachment M, Section 1.0]

Corrosion is a plausible aging mechanism for the Post-Tensioning System, including the ¼ inch diameter prestressing wires, the anchor heads, the shims, and the bearing plates, because they could be exposed to a corrosive environment from a combination of water and moist air intrusion and inadequate initial grease coverage of wires. [Reference 8] Corrosion of prestressing wires causes cracking or a reduction in the wires' cross-sectional area. In either case, the prestressing forces applied to the concrete are reduced. If the prestressing forces are reduced below the design level, a reduction in design margin results. [Reference 5, Attachment M, Sections 1.0 and 2.5]

Prestress Losses - As the plant ages, tendons that were prestressed during construction tend to lose tension. Defined as prestress losses, these reductions in tensile force are not readily observable. Several factors contribute to prestress losses:

- Stress relaxation of prestressing wires;
- Shrinkage, creep, and elastic deformation of concrete;
- Anchorage seating losses;
- Tendon friction; and
- Reduction in wire cross-section due to corrosion that leads to the wire reaching its point of yield.

With the exception of effects due to corrosion-induced wire cross-sectional loss, predictions of prestress losses were calculated during design and margins incorporated at the time of installation of the post-tensioning system to ensure that the Containment Structure can withstand the internal pressure developed during postulated DBEs with no loss of integrity. [Reference 5, Appendix N, Section 1.0]

If the effects of corrosion and prestress losses are allowed to progress unmanaged for an extended period of time, these aging mechanisms could affect the ability of the tendons to support the pressure boundary or fission product retention barrier function of the post-tensioning system by reducing its ability to resist loads imposed by design basis events. Other intended functions (structural or functional support to SR equipment, shelter/protection of SR equipment, and missile barrier) will not be affected because those functions will be provided by the containment wall itself. [Reference 5, Appendix N, Section 2.3]

In 1997, during performance of the 20-year Technical Specification tendon surveillance on Unit 1 Containment Structure, conditions which may represent abnormal degradation of the Containment Structure were found. During testing of selected vertical tendons to determine the lift-off forces, broken wires were discovered. The discovery of broken wires initiated an expansion of the vertical tendon inspection scope to perform visual inspection and lift-off testing on all vertical tendons for both Units 1 and 2. At the completion of the expanded scope, a number of tendons (32% of the vertical tendons or less than 14% of all the tendons) were identified as having severe corrosion (pitting greater than 0.003 inches) and/or broken wires. [Reference 8]

A root cause analysis concluded that tendon wire failures and corrosion problems resulted from a combination of water and moist air intrusion, and inadequate initial grease coverage of wires below the upper stressing washer. This combination created a corrosive environment, which in turn, caused wire failure either by general corrosion or by hydrogen-induced cracking. To slow corrosion and prevent further degradation of the tendon wires, BGE took an immediate short-term compensatory action by localized regreasing of the tendon wires and sealing off the potential moisture leak paths. Baltimore Gas and Electric Company has under consideration a number of options for the long-term corrective actions as outlined in the Containment Tendon Engineering Evaluation Report submitted to the NRC on October 28, 1997. Baltimore Gas and Electric Company has also completed an inspection of all of the vertical tendons in Unit 2. The condition of the Unit 2 tendons are similar to the condition of the Unit 1 tendons. The NRC has indicated that a long-term plan with clearly defined and scheduled actions should be in place prior to restart from the Calvert Cliffs Unit 1 spring 1998 refueling outage. [Reference 9]

Group 1 - corrosion of tendons/prestress losses - Methods to Manage Aging

Mitigation: The effects of tendon corrosion can be mitigated by minimizing the exposure of the post-tensioning system to moisture. Maintaining a good coating of grease on the tendon steel subcomponents would help protect the tendons. [Reference 5, Appendix M, Section 2.1] Prestress losses in tendons were considered in the initial design of the prestress tendon system. [Reference 5, Appendix N, Section 3.0]

Discovery: The effects of tendon corrosion can be detected through visual examination [Reference 5, Appendix M, Section 3.0] Prestress losses in tendons can be discovered by periodically measuring and then monitoring the tendon lift-off forces. [Reference 5, Appendix N, Section 3.0]

Group 1 - corrosion of tendons/prestress losses - Aging Management Program(s)

Mitigation: The design of the containment Post-Tensioning System included provisions for minimizing exposure to water through the use of a petroleum-based grease packed into the tendon sheathing. Maintenance of the grease quality and extent of coverage is performed through periodic inspections of a sample population of tendons in accordance with the Surveillance Test Procedure (STP)-M-663-1/2, "Containment Tendon Surveillance." Refer to the discussion below under Discovery for a detailed description of the surveillance inspection. [Reference 5, Appendix M, Section 2.4] Since there are no methods recommended to mitigate prestress losses at this time, there are no programs credited with mitigating this ARDM.

Discovery: A containment tendon surveillance is periodically performed on the Post-Tensioning System which includes visual examination, lift off measurements, wire tensile testing, and analysis of the sheath filler grease. The tendon surveillance is performed in accordance with CCNPP STP-M-663-1 for Unit 1 and STP-M-663-2 for Unit 2.

Procedure STP-M-663-1 provides instructions for the Unit 1 Containment Tendon Surveillance which includes: [Reference 16, Section 6.0]

- Determining that for a representative sample of dome, vertical, and hoop tendons, each tendon retains a lift-off force equal to or greater than its lower limit expected range for the time of the test.
- Removing one wire from each of a dome, vertical and hoop tendon checked for lift off force, and determining the extent of corrosion and the minimum tensile strength.
- Performing a chemical analysis of the sheath filler grease from the selected surveillance tendons to detect changes in its chemical properties.

The prestressed tendons in CCNPP Unit 1 containment have been tested at 1, 3, 5, 10, 15 and 20 years in accordance with the testing procedure and acceptance criteria specified in STP-M-663-1. For the selected tendon a measurement of the lift-off point pressure is made and converted to lift-off force. This value is compared against a lower bound individual lift-off value. Selected wires are also removed for visual examination and testing. The testing determines the yield strength, ultimate tensile strength, and elongation at ultimate tensile strength. [References 8 and 16]

The visual inspections include an examination of the selected surveillance tendon ends to determine the extent of coverage of the sheathing filler and to detect the presence of water, an examination of all anchorage components for indications of corrosion, pitting, cracking, distortion, or damage, an examination of the surrounding concrete, and an examination of the removed tendon wire for signs of gross corrosion or damage. [References 16 and 17]

A chemical analysis of the sheath filler grease is performed as part of STP-M-663-1 for meeting the inspection requirements of Regulatory Guide 1.35, Revision 2. One sheathing filler grease sample is obtained from each surveillance tendon to be tested for chemical analysis in accordance with ASTM standards. Results of this analysis are evaluated to ensure that the concentration of water soluble impurities and water in the grease sample do not exceed the criteria for chlorides, nitrates, sulfides and water. [Reference 5, Attachment 5; References 16 and 17]

Since both Units' initial one-year surveillances, all testing is typically conducted on Unit 1 and visual examination and sheath filler grease analysis is typically conducted on both units. The visual examination and sheath filler grease analysis for Unit 2 is accomplished as described above for Unit 1. [References 16 and 17]

The prestress force data and physical condition data obtained during each surveillance test is evaluated in accordance with the guidance in Position 7 of Regulatory Guide 1.35, Revision 2, so that the integrity of the prestressed tendon system is ensured. The prestressed tension system is a passive, and highly redundant system. Historical data from CCNPP and from the industry reported very few incidents of random malfunction of the tendons or its components. The criteria provided in the Regulatory Guide 1.35, Revision 2, and adopted by CCNPP will ensure that the tendon system will perform its intended functions through the time interval to the next surveillance. [Reference 5, Attachment 5; References 16 and 17]

The program was altered in 1983 as a result of a Technical Specification change due to the issuance of Regulatory Guide 1.35, Revision 3. The changes were minor and affected the surveillance sample size and the Technical Specification value to which the surveillance results were compared. Another Technical Specification change will result from the new rule recently listed in 10 CFR 50.55(a), incorporating ASME Section XI, Subsection IWE/IWL requirements. Under the new rule, the units will be tested alternately such that 5 tendons (currently 3) per group (hoop, dome, and vertical) are tested in one unit while only a visual inspection is performed for the other unit. In the unit that is tested, the tendon forces are to be measured, one of each type detensioned for wire sample removal, and chemical and material analysis performed on these samples. The visual inspection in the other unit consists of removing end caps, checking the tendon condition and regreasing. Then during the next surveillance, the units will be reversed for tendon testing and visual inspection.

The tendon surveillance inspection program must be revised to extend the lift-off force versus time curve for a 60-year operating life. As a result of this curve revision, the retensioning of selected tendons may be required to meet its resultant revised lift-off force requirements. The existing Technical Specification lift-off force curves were developed for 40 years of operation and do not provide acceptance criteria for any extended period of operation. This is a Time-Limited Aging Analysis issue that will be addressed by re-evaluating the existing curves to reflect the required prestress levels and acceptance criteria for the renewal period. [Reference 18]

Group 1 - corrosion of tendons/prestress losses - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of tendons and prestress losses:

- Containment tendons support the containment pressure boundary or a fission product retention barrier functions; therefore, their integrity must be maintained under current licensing basis (CLB) design loading conditions.
- Containment tendons are susceptible to corrosion and prestress losses, which can affect the ability of the tendons to support the pressure boundary or a fission product retention barrier functions. Other intended functions (structural or functional support to SR equipment, shelter/protection of SR equipment, and missile barrier) will not be affected because those functions will be provided by the containment wall itself.
- Grease coatings mitigate the effects of corrosion by providing a protective layer, preventing moisture and oxygen from contacting the steel.
- A containment tendon surveillance (STP-M-663-1/2) is periodically performed on a sample population of tendons that includes visual examination, lift-off measurements, wire tensile testing, and analysis of the sheath filler grease.
- The existing tendon lift-off force curves will be re-evaluated to reflect the required prestress levels for the period of extended operation.

Therefore, there is reasonable assurance that the effects of corrosion and prestress losses of the containment Post-Tension System will be managed in such a way as to maintain the structures' integrity, consistent with the CLB, during the period of extended operation.

Group 2 - (corrosion of steel) - Materials and Environment

Group 2 is comprised of components that are fabricated from steel, which corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. The Containment Structure component types listed in Table 3.3A-1 and marked with an asterisk are all included within this group. These structural steel components were shop-painted or field-painted during the construction phase, with the exception of grating, wire mesh, checkered plates, and metal decking, which are constructed of galvanized or stainless steel. [Reference 5, Attachment 2 and Appendix K, Sections 1.0 and 2.4]

The following Containment System components are also included in Group 2; containment electrical penetrations, containment mechanical penetrations, containment fuel transfer tube/bellows, containment emergency sump recirculation penetrations, containment personnel air lock, containment emergency air lock, and containment equipment hatch. The electrical penetrations have subcomponents constructed of carbon steel, stainless steel, and non-metallic materials, i.e., epoxy, sealants, and adhesives. The mechanical penetrations, containment personnel air lock, containment emergency air lock, and containment equipment hatch are constructed of carbon steel. The containment fuel transfer tube, containment sump recirculation penetrations, and TSP baskets are constructed of stainless steel and the containment fuel transfer tube bellows is constructed of Inconel. [Reference 6, Attachments 3]

The environment to which these components are subjected varies with their location. In the Containment Structure and Auxiliary Building (where containment penetrations are located), a climate-controlled environment is normally maintained. The ambient temperature is controlled by a plant ventilation system as described in UFSAR Chapter 9. [Reference 1, Table 9-18] The steel components located outdoors will be subject to the temperature and humidity changes, rain, snow, etc. expected at the CCNPP site. In those places where pockets that can harbor liquids are formed by structural components, steel may be subjected to standing water, which is, combined with oxygen, a corrosive environment. [Reference 5, Appendix K, Section 2.1] Penetrations, air locks, and hatches can be exposed to conditions that cause condensation (warm air or water flowing through the component). In the presence of oxygen, such condensation can lead to corrosion if the surface coating is degraded. Some steel components may be exposed to elevated temperatures that could cause the coating to fail. [Reference 6, Attachments 6]

Group 2 - (corrosion of steel) - Aging Mechanism Effects

Steel corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. Initially, the exposed steel surface reacts with oxygen and moisture to form an oxide film as rust. Once the protective oxide film has been formed and if it is not disturbed by erosion, alternating wetting and drying, or other surface actions, the oxidation rate will diminish rapidly with time. Chlorides, either from seawater, the atmosphere, or groundwater, increase the rate of corrosion by increasing the electrochemical activity. If steel is in contact with another metal that is more noble in the galvanic series, corrosion may accelerate. Corrosion is plausible for all components and subcomponents constructed of carbon steel or galvanized steel. Corrosion is not plausible for the containment fuel transfer tube and bellows, containment emergency sump recirculation penetrations, and TSP baskets because they are constructed of stainless steel or Inconnel, which are highly resistant to general corrosion. Corrosion is also not plausible for the containment emergency sump cover and screen mesh and grating because they are constructed of stainless steel. Corrosion is plausible for the containment emergency sump cover and screen structural steel because it is constructed of carbon steel. If corrosion is left unmanaged for an extended period of time, the resulting loss of material could lead to the inability of the Group 2 steel components to perform their intended functions under CLB design loading conditions. [Reference 5, Attachment 2 and Appendix K, Section 1.0; Reference 6, Attachments 5 and 6]

In some cases, corrosion of carbon steel that is in contact with water may be microbiologically induced due to the presence of certain organisms. These organisms, which include microscopic forms such as bacteria and macroscopic types such as algae and barnacles, may influence corrosion of steel under broad ranges of pressure, temperature, humidity, and pH. Microbiologically-induced corrosion is plausible for structural steel components where water may collect and could result in random pitting and general corrosion. [Reference 5, Appendix K, Sections 1.0 and 2.1] Microbiologically-induced corrosion is not plausible for the electrical penetrations, mechanical penetrations, containment sump recirculation penetrations, containment personnel air lock, containment emergency air lock, and containment equipment hatch because they are not wetted surfaces. Microbiologically-induced corrosion is not plausible for the containment fuel transfer tube due to insufficient tensile stresses, use of corrosion resistant materials, controlled refueling water chemistry, and because it is maintained dry except during refueling periods. [Reference 6, Attachments 5 and 6] If microbiologically-induced corrosion is left unmanaged for an extended period of time, the resulting loss of material could lead to the inability of the Group 2 steel components to perform their intended functions under CLB design loading conditions.

Corrosion products such as hydrated oxides of iron (rust) form on exposed, unprotected surfaces of the steel and are readily visible. The affected surface may degrade to such an extent that visible perforation may occur. In the case of exposed surfaces of steel with protective coatings, corrosion may cause the protective coatings to lose their ability to adhere to the corroding surface. In this case, damage to the coatings can be visually detected well in advance of significant degradation of the steel. [Reference 5, Appendix K, Section 1.0]

In 1992, a visual inspection was performed for the interior of containment, including some containment penetrations, structural steel floor frames, and equipment support interfaces. The coatings were observed to be in good condition and only minimal corrosion was observed. The exterior of the Containment Structure was also visually inspected. Some minor rust stains were observed on the concrete from metal components such as uncoated steel anchors and skyclimber structural steel supports. There was also evidence of some deterioration of the protective coating on the buttress bearing plates and tendon grease caps. The methodology employed for the inspection was consistent with the industry standard, "Rules for Inservice Inspection, Section XI, ASME Boiler and Pressure Vessel Code," which gives rules for the inspection of concrete. Under these rules, the exterior and interior surfaces of the Containment Structure and components in the Containment System were found to be in good to excellent condition. The responsible engineer determined by visual examination that there was no evidence of damage or degradation sufficient to warrant further evaluation or repair.

A routine walkdown of containment penetrations was also performed in the Unit 2 Containment in 1995 in accordance with Administrative Procedure MN-3-100, "Painting and other Protective Coatings." Some penetrations showed indications of rust/scale/corrosion inside the containment. An Issue Report was initiated in accordance with the CCNPP Corrective Actions Program, and it was determined that the corrosion would be monitored and corrected under MN-3-100. In 1997, the rust/scale/corrosion was removed and the surfaces repainted in accordance with MN-3-100.

Group 2 - (corrosion of steel) - Methods to Manage Aging

Mitigation: The effects of corrosion can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment and protecting the external surfaces with paint or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces.

Discovery: The effects of corrosion of steel are detectable by visual inspection. The external metal surfaces of structural steel components are covered by a protective coating, and observation that significant degradation has not occurred to this coating is an effective method to ensure that corrosion has not affected the intended function of the structural component. Coatings degrade slowly over time, allowing visual detection as part of routine walkdowns during normal plant operations. Coatings that are blistered or showing rust stains have degraded to the point where the steel is being exposed to moisture and oxygen. Since the coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition that triggers corrective action before corrosion that affects the components' ability to perform its intended function can occur. The degradation of the protective coating that does occur can be discovered and monitored by periodically inspecting the carbon steel structural components and by carrying out corrective action as necessary. [Reference 5, Attachment 8 and Appendix K, Section 3.0]

Group 2 - (corrosion of steel) - Aging Management Program(s)

Mitigation: The exposed metal surfaces of carbon steel structural components are covered by protective coatings that mitigate the effects of corrosion. The discovery programs discussed below ensure that the protective coatings of carbon steel structural components are maintained.

Discovery: Corrosion of steel can readily be detected for Group 2 components through visual examination. Additionally, degradation of protective coatings, which help mitigate corrosion, can also be visually detected so that corrective actions can be taken to restore the coatings. An inspection program can provide the assurance needed to conclude that the effects of corrosion are being effectively managed for the period of extended operation. Routine walkdowns of the Primary Containment would provide for discovery and management of corrosion of Group 2 components. Because the wire mesh on the containment emergency sump cover and screen blocks the view of the structural steel supports, a separate visual examination is conducted for that component. [Reference 5, Appendix K, Attachment 4; Reference 6, Attachment 2]

Structure and System Walkdowns

Periodic walkdowns that are performed for CCNPP structures and systems provide opportunities to visually inspect the condition of plant equipment and to identify degraded conditions. Two procedures that specifically control walkdown activities that could identify and correct potential corrosion or degraded protective coatings for the Containment Structure and Containment System are CCNPP Administrative Procedures MN-3-100 and MN-1-319, "Structure and System Walkdowns." Each of these procedures are discussed below.

Administrative Procedure MN-3-100 provides for discovery of corrosion of steel or of conditions that would allow corrosion to occur, such as degraded paint, for the inside of containment through performance of visual inspections during plant walkdowns. The purpose of Procedure MN-3-100 is to control painting and protective coatings activities performed inside containment to ensure they comply with Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," and American National Standards Institute (ANSI) N101.4 - 1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." Containment walkdowns performed in accordance with this procedure are credited for discovery and management of corrosion of Group 2 steel components inside of containment. [Reference 5, Appendix K; Reference 19, Section 1.1]

Procedure MN-3-100 requires that the responsible engineer perform a walkdown of the inside of containment at the start of each scheduled refueling or maintenance outage to verify the condition of all Service Level I coatings. Service Level I coatings are those where failure could adversely affect the operation of post-accident fluid systems and, thereby, impair safe shutdown. MN-3-100 also controls the identification of correct Service Level and specifies minimum requirements for coating quality and work practices. [Reference 19, Sections 3, 5.2 and 5.3]

During the containment walkdown, a general visual inspection is performed on all readily accessible surfaces. A more thorough inspection is performed on all coatings near sumps or screens associated with the Emergency Core Cooling System. The inspector develops a list of all areas inside containment exhibiting deterioration. Repair areas are evaluated to ensure timely corrective action is taken. All routine and restorative coatings work is prioritized and implemented in accordance with the CCNPP Corrective Actions Program. [Reference 19, Section 5.2]

Controls for painting and other protective coatings have been in existence since initial plant startup. During that time, changes to the program have been made largely due to an existing qualified paint becoming unavailable. There have been no changes made specifically to address particular aging-related or coating-related problems or failures.

Administrative Procedure MN-1-319 provides for discovery of corrosion of steel or of conditions that would allow corrosion to occur, such as degraded paint, for the outside of containment through performance of visual inspections during plant walkdowns. The purpose of the procedure is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. System walkdowns are credited for discovery and management of corrosion of Group 2 steel components outside of containment. [Reference 6, Attachment 1; Reference 20]

Under MN-1-319, responsible personnel perform periodic walkdowns of their assigned structures and systems. Walkdowns may also be performed as required for reasons such as: material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when the system is initially pressurized, energized, or placed in service); and as required for plant modifications. Currently, structure walkdowns should be performed every refueling outage and scheduled to ensure that every structure will receive a walkdown as a minimum every third outage. [Reference 20, Sections 5.1 and 5.3]

One of the objectives of the walkdowns is to assess the condition of the CCNPP structures, systems, and components such that any abnormal or degraded condition will be identified, documented, and corrective actions taken before the condition proceeds to failure of the structures, systems, and components to perform their intended functions. Conditions adverse to quality are documented and resolved by the CCNPP Corrective Actions Program and in accordance with MN-3-100. [Reference 20, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The walkdown procedure provides guidance for identification of specific types of degradation or conditions when performing the walkdowns. Inspection items related to aging management include the following: [Reference 20, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

The procedure includes a walkdown checklist specifically for the Containment Structure. The checklist includes a section targeted at structural steel components. Checklist items include visual inspection for corrosion, rust stains, and flaking/bubbling of protective coatings. A checklist for moisture barriers includes visual inspection for standing water, water intrusion, water marks, or corrosion of metal components. [Reference 20, Attachment 3]

The structure and system walkdowns enhance the familiarity of responsible personnel with their assigned systems and structures and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance personnel alone. The procedure has been improved recently through incorporation of significant additional guidance on specific activities to be included in the scope of the structures walkdowns. Further enhancements will be made to provide guidance to help the person performing the walkdown in determining whether the intended functions will continue to be met as required by the CLB and guidance regarding approval authority for significant departures from scope or schedule.

The walkdowns described above will ensure that degraded conditions due to corrosion of steel are identified and corrected such that Group 2 components will be capable of performing their intended functions under all CLB conditions.

Emergency Sump Cover and Screen Inspection

The containment emergency sump cover and screen contains a wire mesh for trapping debris that could potentially be swept up by the safety injection pumps when containment spray is in the recirculation mode. This wire mesh obstructs the view of the structural steel that frames the grating and mesh screen. Therefore, the routine walkdowns performed under MN-3-100 are not relied on for discovery of corrosion for this component. A Surveillance Test Procedure, STP-M-661-1/2, "Containment Emergency Sump Inspection," is performed every refueling outage in accordance with plant Technical Specifications, and is credited for the required visual inspection.

Procedure STP-M-661-1/2 provides for discovery of corrosion of the structural steel components of the cover and screen through performance of visual inspections. These inspections would also detect any degraded paint conditions that, if left uncorrected, could lead to the steel being exposed to a corrosive environment. Specifically, the procedure requires an inspection for signs of corrosion, debris, or structural distress to the screens. Any deficiencies are noted and corrective actions initiated in accordance with the CCNPP Corrective Actions Program. The visual inspections performed by STP-M-661-1/2 will ensure that degraded conditions due to corrosion of the cover and screen structural steel are detected and corrected such that the cover and screen will be capable of performing its intended function under all CLB conditions. [References 21 and 22]

Group 2 - (corrosion of steel) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of steel in the Group 2 components:

- The structural steel components, penetrations, air locks, and hatches that comprise Group 2 provide passive intended functions (refer to Table 3.3A-1) and their integrity must be maintained under all CLB conditions.
- Corrosion of steel is plausible due to possible degradation of the external protective coatings and exposure to water and oxygen.
- Periodic visual inspections of coated surfaces inside of containment will continue to be performed in accordance with MN-3-100. Procedure MN-3-100 also controls the assessment, prioritization, and corrective action for degraded coatings discovered outside containment. Corrective actions are taken in accordance with the CCNPP Corrective Actions Program.
- Periodic visual inspections of coated surfaces outside of containment will continue to be performed in accordance with CCNPP Administrative Procedure MN-1-319. The procedure will be modified to provide guidance to assist in functional adequacy determinations and for authority to deviate

from scope or schedule. These walkdowns will identify and document significant coating degradation and/or presence of corrosion.

- Periodic visual inspections of the structural steel members of the containment emergency sump cover and screen will continue to be performed in accordance with CCNPP Surveillance Test Procedures STP-M-661-1/2. Any significant coating degradation or corrosion will be discovered and corrective actions will be taken in accordance with the CCNPP Corrective Actions Program.

Therefore, there is reasonable assurance that the effects of aging due to corrosion of steel will be managed in such a way that Containment Structural and System components will be capable of performing their intended functions consistent with the CLB during the period of extended operation.

Group 3 - (corrosion of containment wall and dome liners) - Materials and Environment

The containment wall and dome liners at CCNPP are ASTM A36 carbon steel. These liners were constructed from a series of individual steel plates welded together. Both the plate material and the welds are subject to the same potential degradation mechanisms. The significance of potential degradation of the liners is considered to apply equally to the plate material and the welds. For corrosion protection, the inside face of the containment wall and dome liners were covered with a protective coating during the construction phase. The containment wall and dome liners do not have dissimilar metals; therefore, they are not subject to galvanic corrosion. [Reference 5, Attachment L, Sections 2.0 and 2.4]

The containment wall and the containment dome are 3'-9" and 3'-3" thick, respectively, and are subject to compressive stress due to dead weight and prestress load under normal plant operating conditions. Any cracks that do occur would be more tightly closed due to the prestress forces, allowing less potential for groundwater to penetrate to the containment wall liner. This configuration minimizes cracks in the concrete that allow penetration of moisture, oxygen, and chlorides, which cause corrosion degradation. Therefore, the containment wall liner from the concrete side and the liner anchors are not exposed to aggressive chemicals from the outside environment, such as acid rain, salt-containing atmospheres, and groundwater. [Reference 5, Attachment L, Sections 2.1.1 and 2.5]

The interior surfaces of the containment wall and dome liners are exposed to the containment internal environment. The Primary Containment Heating and Ventilation System maintains a climate-controlled environment inside the containment with design conditions as described in Table 9-18 of the UFSAR. Corrosion of the internal surfaces could occur in the presence of moisture and oxygen as a result of electrochemical reactions unless the existing coating is maintained by an effective coating management program. [Reference 5, Attachment L, Section 2.1.1]

Group 3 - (corrosion of containment wall and dome liners) - Aging Mechanism Effects

Carbon steel corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. Initially, the exposed steel surface reacts with oxygen and moisture to form an oxide film as rust. Once the protective oxide film has been formed and if it is not disturbed by erosion, alternating wetting and drying, or other surface actions, the oxidation rate will diminish rapidly with time. Chlorides, either from bay water, the atmosphere, or groundwater, increase the rate of corrosion by increasing the electrochemical activity. Corrosion products such as hydrated oxides of iron (rust) form on exposed, unprotected surfaces of the steel and are readily visible. The affected surface may degrade to such an extent that visible perforation may occur. In the case of exposed surfaces of steel with protective coatings, corrosion may cause the protective coatings to lose their ability to adhere to the corroding surface. In this case, damage to the coatings can be visually detected well in advance of significant degradation of the steel. [Reference 5, Appendix K, Section 1.0 and Appendix L, Section 1.1]

Corrosion is plausible for the internal surfaces of the containment wall and dome liners because they are potentially subject to moisture and oxygen and are constructed of carbon steel. If corrosion of the internal surfaces of the containment wall and dome liners is left unmanaged for an extended period of time, the resulting loss of material could lead to the inability of these steel components to perform their intended functions under CLB design loading conditions. [Reference 5, Appendix K, Section 2.3]

Group 3 - (corrosion of containment wall and dome liners) - Methods to Manage Aging

Mitigation: The effects of corrosion can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment by protecting the external surfaces with paint or other protective coating. Maintaining the protective coating on the interior surfaces of the liner prevents moisture and oxygen from directly contacting the steel surfaces of the containment wall and dome liners. [Reference 5, Appendix K, Section 2.6]

Discovery: The effects of corrosion of steel are detectable by visual inspection. A visual examination by a person familiar with the liners can be used to determine general mechanical and structural condition and check for rust. Observing that significant degradation of protective coatings has not occurred is an effective method to ensure that corrosion has not affected the intended function of the structural component. Since the coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition that can trigger corrective action before the occurrence of corrosion that would affect the components' ability to perform their intended functions. The degradation of the protective coating that does occur can be discovered and monitored through visual inspections. Corrective actions for failed protective coatings and any actual metal degradation can be carried out as necessary. [Reference 5, Appendix L, Section 3]

Group 3 - (corrosion of containment wall and dome liners) - Aging Management Program(s)

Mitigation: The containment wall and dome liners are covered by protective coatings that mitigate the effects of corrosion. The discovery programs discussed below ensure that the protective coatings of carbon steel structural components are maintained. [Reference 5, Appendix L, Section 3]

Discovery: Corrosion of the containment wall and dome liners can readily be detected through visual examination. Additionally, degradation of protective coatings, which help mitigate corrosion, can also be visually detected so that corrective actions can be taken to restore the coatings. An inspection program can provide the assurance needed to conclude that the effects of corrosion are being effectively managed for the period of extended operation. [Reference 5, Appendix L, Section 3]

An examination of the containment liner plate is periodically performed in accordance with CCNPP Surveillance Test Procedure STP-M-665-1, "Containment Liner Plate Surveillance," for Unit 1 and STP-M-665-2, "Containment Liner Plate Surveillance," for Unit 2. STP-M-665-1/2 are currently performed as specified in the Containment Leakage Rate Testing Program, i.e., prior to the performance of an Integrated Leak Rate Test and during two other refueling outages before the next Integrated Leak Rate Test, in accordance with ASME Section XI, 1992 Subsections IWE and IWL, if the interval for the

Integrated Leak Rate Test has been extended to 10 years. The tests specifically address Technical Specification Surveillance Requirement 4.6.1.6.3 to visually inspect the exposed accessible interior and exterior surfaces of the Containment Structure. If any portion of the liner plate shows any signs of bulges, wrinkles, cracks, corrosion, flaking paint, or indication of other types of deterioration, corrective actions are required. Corrective actions are completed in accordance with the CCNPP Corrective Actions Program. [References 23, 24, and 25]

Recent inspections of the containment liners in accordance with STP-M-665 revealed that the liner plate was in good condition, except in the immediate vicinity of the expansion joint between the floor slab and liner plate. After approximately 20 years of operation, the original joint sealant, Thiokol Polysulfide, was deteriorating. Blistering of the paint and corrosion of the liner was observed at the joints as evidence of water intrusion. No through-liner flaws were found. Due to these discoveries, the Thiokol Polysulfide base sealant is being replaced with a High Density Silicone Elastomer (HDSE) that provides an effective barrier against water as well as smoke, gas, pressure, and fire. High Density Silicone Elastomer has high thermal stability and structural strength. Besides using a different sealant material, the design of the joint seal is also being modified. Originally, the Thiokol Polysulfide base sealant was applied to a shallow depth at the top of the compressible material in the joints and made flush with the nominal 10-foot elevation base slab. The new HDSE sealant is being used to form a small curb above the joint to shed water in addition to providing a seal. Also, to improve the seal, the HDSE is being placed a minimum of three inches into the joint after removing some compressible material. A polyethylene backer rod is being placed in the joint between the HDSE and compressible material to separate them. Any required repair, cleaning, and repainting of the liner is being performed as part of this activity. This repair was already performed on the Unit 1 moisture barrier during the 1996 refueling outage. At that time, all of the liner plate was determined to be of adequate thickness in the area of the moisture barrier. Repairs to the expansion joints in Unit 2 are currently scheduled for the refueling outage in 1999. Thus, based on these actions, it can be concluded that the existing program, STP-M-665, adequately inspects the liner in the area of the seal and compressible material.

Group 3 - (corrosion of containment wall and dome liners) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of the containment wall and dome liners:

- The containment wall and dome liners support a pressure boundary or fission product retention barrier function to protect the public health and safety in the event of any postulated DBEs, and their integrity must be maintained under all CLB conditions.
- Corrosion of the inside surface of the containment wall and dome steel liner plates is plausible due to possible degradation of the external protective coatings and exposure to water and oxygen. If left unmanaged, corrosion could eventually result in the liner plates not being able to perform their intended functions under CLB conditions
- Periodic visual inspections of the containment wall and dome liners will continue to be performed in accordance Surveillance Test Procedures STP-M-665-1/2. These inspections will identify and document significant coating degradation and/or presence of corrosion. Corrective actions are taken in accordance with the CCNPP Corrective Actions Program.

Therefore, there is reasonable assurance that the effects of aging due to corrosion of the containment wall and dome liners will be managed in such a way that they will be capable of performing their intended functions consistent with the CLB during the period of extended operation.

Group 4 - (corrosion of the refueling pool liner and PCSR) - Materials and Environment

The refueling pool liner at CCNPP is constructed of Type 304 stainless steel material. The liner was constructed from a series of individual steel plates welded together. All exposed metal parts of the PCSR are constructed of Type 304 stainless steel. The hatch bolts for the PCSR are stainless steel. The refueling pool liner and PCSR do not have dissimilar metals; therefore, they are not subject to galvanic corrosion. [Reference 1, Section 11.2.2.4; Reference 5, Attachment L, Sections 2.0 and 2.4]

The stainless steel liner and PCSR are not load-bearing structural components, since the induced strains in the liner and PCSR are negligible under normal plant operating conditions. The heat affected zones of the welds are potential sites for “sensitization.” The internal surfaces of the refueling pool liner and PCSR are normally dry. However, during refueling outages they are exposed to water that contains boric acid. Sensitized Type 304 stainless steel is susceptible to IGSCC in boric acid solution. [Reference 5, Appendix L, Section 2.1.3]

Group 4 - (corrosion of the refueling pool liner and PCSR) - Aging Mechanism Effects

SA-240 Type 304 stainless steel is resistant to electrochemical corrosion in the refueling pool environment. The corrosion rate of this steel ranges from 0.05 mil in 100 years (virtually no corrosion) to less than 0.001 mil per year in a borated fuel pool water environment. Therefore, the electrochemical corrosion is negligible for the refueling pool liner and PCSR. Furthermore, since the liner and PCSR are not exposed to a corrosive environment and the induced strains are negligible under normal operating conditions, the conditions for stress corrosion cracking to occur do not exist for the refueling pool liner or PCSR. [Reference 5, Appendix L, Section 3.1.3]

The heat affected zones of the welds are potential sites for sensitization. This is because of the changes in the microstructure that take place due to the welding heat, rendering the heat affected zones sensitized, and because of the potential for high residual stresses in and around the welds. Sensitized Type 304 stainless steel may be susceptible to IGSCC in boric acid solution (13,000 ppm) at temperatures of 180°F and low pH (less than 4). Conditions that may contribute to the occurrence of IGSCC include elevated temperatures, chloride content, boric acid concentration, oxygen concentration, and degree of sensitization. [Reference 5, Appendix L, Section 2.1.3; Reference 26, Section 4.5.1.1]

Intergranular stress corrosion cracking of the stainless steel liner and PCSR would be expected to result in initiation and propagation of a crack that can eventually lead to detectable leakage. If IGSCC of the refueling pool liner and PCSR is left unmanaged for an extended period of time, the resulting cracks could lead to the inability of these stainless steel components to perform their intended functions under CLB design loading conditions. [Reference 5, Appendix L, Sections 2.1.3 and 2.3]

The general condition of the refueling pool is good with no apparent signs of aging. There has been minimal leakage to date, where at one location in Unit 2, it may originate from drain pipes, not from the liner or PCSR. The exact location of this leakage is still being investigated. However, the leakage was evaluated for its effects on the rebar in the concrete and was shown to have a negligible effect on slab strength. The refueling pool drain pipe is addressed in Section 5.18, "Spent Fuel Pool Cooling System," of the BGE LRA. One additional leak is currently being investigated and the leak source will be repaired if necessary. The refueling pool is typically dry and is filled during refueling outages only. There has been no evidence of IGSCC identified in the liner or PCSR welds. A visual inspection of two welds closest to the highest stress region of the PCSR was performed one cycle (two years) after the PCSR was installed. No service-induced indications were discovered.

Group 4 - (corrosion of the refueling pool liner and PCSR) - Methods to Manage Aging

Mitigation: The effects of IGSCC can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment. However, the discovery methods described below are deemed adequate to manage these ARDMs.

Discovery: The effects of IGSCC of heat affected welds could result in material cracking and could cause the refueling pool liner or PCSR to leak. Because the liner and PCSR only serve as fluid retaining boundaries and do not provide a structural integrity function, detecting and, if needed, measuring and trending leakage from the refueling pool provides for effective aging management. Corrective measures can be taken to restore the refueling pool's integrity if any significant leakage is detected. [Reference 5, Appendix L, Section 3]

Group 4 - (corrosion of the refueling pool liner and PCSR) - Aging Management Program(s)

Mitigation: Since there are no methods recommended to mitigate corrosion at this time, there are no programs credited with mitigating this ARDM. [Reference 5, Appendix L, Section 3]

Discovery: Detecting, and if needed, measuring and trending leakage from the refueling pool and PCSR provides for discovery of IGSCC so that corrective measures can be taken prior to loss of intended function. Routine inspections are performed on system components in accordance with CCNPP Administrative Procedure MN-1-319. These walkdowns provide for discovery and management of the effects of corrosion through visual inspections, reporting any leakage detected, and initiating corrective action. Under this procedure, any evidence of fluid leakage would be considered adverse to quality and, therefore, addressed in accordance with the CCNPP Corrective Actions Program. [Reference 20] Refer to the discussion on Aging Management Programs for Group 2 for a detailed description of MN-1-319.

Group 4 - (corrosion of the refueling pool liner and PCSR) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of the refueling pool liner and PCSR:

- The refueling pool liner and PCSR support a pressure boundary or fission product retention barrier function to protect the public health and safety in the event of any postulated DBEs and their integrity must be maintained under all CLB conditions.
- IGSCC on the inside surface on the refueling pool liner plates or PCSR is plausible due to potential sensitization of the steel at weld locations and a corrosive environment of borated water. If left unmanaged, IGSCC could eventually result in the refueling pool liner or PCSR not being able to perform their intended function under CLB conditions

- Periodic walkdowns of the containment will continue to be performed in accordance with Procedure MN-1-319. These inspections will identify and document the presence of leaks that may be due to IGSCC.

Therefore, there is reasonable assurance that the effects of aging due to IGSCC of the refueling pool liner and PCSR will be managed in such a way that they will be capable of performing their intended function consistent with the CLB during the period of extended operation.

Group 5 - (weathering of grout) - Materials and Environment

The Containment Structures at CCNPP are prestressed, post-tensioned concrete structures. During the post-tensioning activities during initial construction, reports were made that 11 of the top bearing plates of the vertical tendons on Unit 1 and 1 of these plates on Unit 2 depressed into the concrete. Further investigations verified that voids exist under many of the vertical tendon bearing plates. Refer to Appendix 5D, "Study of Upper Vertical Tendon Bearing Plates," of the UFSAR for a detailed discussion of the vertical tendon bearing plate repairs. Grout was used to make repairs to all bearing plates that showed indications of voids in the concrete below. [Reference 1, Appendix 5D.1.1]

Since the grout is located on top of the Containment Building, it is subject to the normal outside atmosphere conditions at the CCNPP site. The CCNPP site is located in a geographic region subject to severe weather conditions. All outdoor components will experience the extreme temperature ranges, rain, snow, and changes in humidity expected at the CCNPP site. [Reference 5, Appendix O]

Group 5 - (weathering of grout) - Aging Mechanism Effects

The grout at the containment tendon bearing plates is exposed to outdoor weather conditions and is susceptible to weathering. Aging mechanisms associated with weathering include exposure to sunlight (ultraviolet exposure), changes in humidity, ozone cycles, temperature and pressure fluctuations, and snow, rain, or ice. The effects of weathering on grout is evidenced by cracking and spalling. [Reference 5, Appendix O]

The durability of grout may affect the passive intended function it provides. Although aggressive environments may contribute to deterioration of the grout, most degradation results from water entering cracks in and around the grout and freezing. This is an ongoing process throughout the plant's life that results in cracking and spalling at susceptible locations. Some of the grout locations are in flat areas of the structure and are exposed to standing water.

An inspection of the Unit 1 Containment Structure was performed in 1992, which included a representative sample of the grout at the vertical tendon base plates. It was observed that the mortar generally showed some tight cracks, visually estimated to be about 0.005 inch, which is just big enough to show a moisture trail when water is present. The mortar appeared to be in good condition with no immediate repairs needed.

Group 5 - (weathering of grout) - Methods to Manage Aging

Mitigation: No methods for mitigating weathering of grout are needed; the discovery methods described below are deemed adequate to manage this ARDM.

Discovery: The effects of weathering of grout are detectable by visual inspection. Periodic visual examinations would provide for discovery of degraded grout so that corrective actions could be taken to preclude the effects of weathering from affecting the intended function of the grout.

Group 5 - (weathering of grout) - Aging Management Program(s)

Mitigation: Since no methods for mitigation are needed at this time, there are no mitigation programs required.

Discovery: The effects of weathering on the containment tendon baseplate grout is readily detected through visual observation. A containment tendon surveillance is periodically performed on the Post-Tensioning System that includes visual examination, lift off measurements, wire tensile testing, and analysis of the sheath filler grease. The tendon surveillance is performed in accordance with CCNPP Surveillance Test Procedure STP-M-663-1 for Unit 1 and STP-M-663-2 for Unit 2.

Procedures STP-M-663-1/2 are currently performed at five-year intervals in accordance with the plant Technical Specifications. The tests specifically addresses Technical Specification Surveillance Requirement 4.6.1.6.2 to verify the structural integrity of the end anchorages and adjacent concrete exterior surfaces. If any adjacent concrete shows indications of abnormal material behavior (e.g., cracking or spalling), an engineering evaluation to demonstrate the ability of the Containment Structure to continue to perform its design function is completed in accordance with Technical Specification 3.6.1.6.b. Refer to the discussion under Aging Management Programs in Group 1 for a detailed discussion of these STPs. [References 16 and 17]

Group 5 - (weathering of grout) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to weathering of grout at the containment vertical tendon base plates:

- The grout provides structural support to the containment tendons and its integrity must be maintained under all CLB conditions.
- Weathering is plausible due to exposure to severe weather conditions and, if left unmanaged, it could eventually result in the grout not being able to perform its intended function under CLB conditions.
- Periodic visual inspections of the grout will continue to be performed in accordance with CCNPP Surveillance Testing Procedure STP-M-663-1/2. These inspections will discover the effects of weathering and assure that the necessary evaluations are performed to demonstrate the ability of the containment structure to continue to perform its design function.

Therefore, there is reasonable assurance that the effects of aging due to weathering of containment vertical tendon baseplate grout will be managed in such a way that it will be capable of performing its intended function consistent with the CLB during the period of extended operation.

3.3A.3 Conclusion

The aging management programs discussed for the Primary Containment Structure and System are listed in the following Table 3.3A-4. These programs are (or will be for new programs) administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects in such a way that the intended functions of the components of the Primary Containment will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 3.3A-4

LIST OF AGING MANAGEMENT PROGRAMS FOR PRIMARY CONTAINMENT

	Program	Credited As
Existing	Preventive Maintenance Program Procedure PAL-2	Aging management of emergency air lock gaskets by replacement based on condition.
Existing	Containment Emergency Sump Inspection Procedures STP-M-661-1 for Unit 1, and STP-M-661-2 for Unit 2	Discovery and management of the effects of corrosion on the containment emergency sump cover and screen by visual inspection. (Group 2)
Existing	Painting and Other Protective Coatings (MN-3-100)	Discovery and management of degraded protective coatings and the effects of corrosion on steel components inside the Containment Structure. (Group 2)
Existing	Liner Plate Surveillance Test Procedures STP-M-665-1 for Unit 1 and STP-M-665-2 for Unit 2	Discovery and management of degraded protective coatings and the effects of corrosion on the containment wall and dome liners. (Group 3)
Modified	Containment Tendon Surveillance Test Procedures STP-M-663-1 for Unit 1 and STP-M-663-2 for Unit 2	Discovery and management of the effects of corrosion on the containment tendons by visual inspection and analysis of the filler grease. (Group 1) Discovery and management of prestress losses for the containment tendons by performance of lift-off tests and wire tensile tests. The existing tendon lift-off force curves will be re-evaluated to reflect the required prestress levels for the period of extended operation. (Group 1) Discovery and management of the effects of weathering of grout by visual inspection. (Group 5)
Modified	Structure and System Walkdowns (MN-1-319)	Discovery and management of the effects of corrosion on steel components outside the Containment Structure. Guidance will be added to assist in functional adequacy determinations and for authority to deviate from scope or schedule. (Group 2) Discovery and management of the effects of corrosion on the refueling pool liner and PCSR by monitoring leakage. (Group 4)

3.3A.4 References

1. CCNPP Updated Final Safety Analysis Report, Revision 21
2. CCNPP Drawing 61230, "Salt Water Systems Underground Ducts Plan and Sections," Revision 6, October 15, 1990
3. CCNPP Drawing 63874SH0004, "SR Ductbank Under West Plant Road Plan," Revision 0, April 4, 1995
4. CCNPP Drawing 63874SH0005, "Underground Conduit West of Turbine Building Plan," Revision 0, July 15, 1996
5. CCNPP Report "Aging Management Review Report for the Containment Structure (System 059)," Revision 4, February 1997
6. CCNPP Report "Aging Management Review Report for the Containment System (059)," Revision 1, May 1996
7. CCNPP "Aging Management Review Report for Component Supports," Revision 3, February 4, 1997
8. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated October 28, 1997, "Containment Tendon Engineering Evaluation Report"
9. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), dated January 23, 1998, Review of Containment Tendon Evaluation Report - CCNPP Unit Nos. 1 and 2 (TAC Nos. M99880 and M99881)
10. CCNPP Report, "Component Level Scoping Results for the Containment Structure," Revision 2, February 11, 1997
11. CCNPP Report, "Component Level ITLR Screening Results for the Containment System," Revision 0, February 23, 1993
12. CCNPP Preventive Maintenance Checklist MPM00109, "Replace Gaskets for Equipment Hatch"
13. CCNPP Preventive Maintenance Checklist MPM00108, "Replace Gaskets for Personnel Air Lock Door"
14. CCNPP Technical Procedure PAL-2, "Containment Personnel Emergency Escape Air Lock Adjustment, Lubrication, and Inspection (Units 1 and 2)," Revision 1, February 5, 1993
15. Electric Power Research Institute Report TR-103835, "PWR Containment Structures License Renewal Industry Report," Revision 1, July 1994
16. CCNPP Surveillance Test Procedure STP-M-663-1, "Containment Tendon Surveillance," Revision 9, August 21, 1997
17. CCNPP Surveillance Test Procedure STP-M-663-2, "Containment Tendon Surveillance," Revision 7, October 1, 1997
18. CCNPP Report, Time Limited Aging Analysis Review Report," Revision 0, November 1997
19. CCNPP Administrative Procedure MN-3-100, "Painting and Other Protective Coatings," Revision 4, March 10, 1997

3.3B Turbine Building Structure

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Turbine Building Structure (henceforth called the Turbine Building). The Turbine Building was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

3.3B.1 Scoping

The system level scoping process defines conceptual boundaries for plant systems and structures, develops screening tools that capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Systems and structures that are within the scope of license renewal are then scoped further on a component level. [Reference 1, Section 3.0]

The component level scoping process for systems is described in Section 4.1 of the CCNPP IPA Methodology, and the component level scoping process for structures is described in Section 4.2 of the methodology. Components with unique equipment identifiers in the site equipment database are scoped using the component level scoping process for systems. Structural components such as walls do not have unique equipment identifiers. Therefore, the component level scoping process for structures utilizes a generic listing of structural component types. [Reference 1, Section 4.0]

The component level scoping process for structures identifies structural type components as being within the scope of license renewal if they perform one or more of the following generic structural functions: [Reference 1, Section 4.2.2]

- Provide structural and/or functional support to safety-related (SR) equipment;
- Provide shelter/protection to SR equipment;
- Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated Design Basis Events;
- Serve as a missile barrier (internal or external);
- Provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions;
- Provide flood protection barrier (internal flooding event); and
- Provide a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.

The remainder of Section 3.3B.1 provides a description of the Turbine Building including the conceptual boundaries from the system level scoping results, the results of the component level scoping, and the results of the scoping to determine the components subject to aging management review (AMR).

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

Structure Description/Conceptual Boundaries

Figure 3.3B-1 is a simplified layout of site structures, including the Turbine Building, showing the structures that are within the scope of license renewal. The CCNPP site arrangement consists of numerous structures as shown on Figure 1-2 of the CCNPP Updated Final Safety Analysis Report (UFSAR). Design features of the CCNPP structures are discussed in UFSAR Chapter 5. [Reference 2; Reference 3, Table 2; References 4, 5, and 6]

The Turbine Building is oriented parallel to the Chesapeake Bay shoreline between the North Service Building (which is located on the east, or bay side) and the Auxiliary Building (which is located on the west, or landward side). The Turbine Building is common to CCNPP Units 1 and 2. The Turbine Building houses the turbine-generators, condensers, feedwater heaters, condensate and feed pumps, turbine auxiliaries, and switchgear assemblies. [Reference 2, Figure 1-2, Section 1.2.2]

The Turbine Building is a steel structure, with metal siding, supported on reinforced concrete foundations. The circulating water intake and discharge conduits are incorporated into the spread footings. The turbine-generators are separated by an expansion joint in the superstructure. [Reference 2, Section 5.6.3; Reference 7, Section 1.1.1]

The Turbine Building is a Seismic Category II structure with the exception of the Auxiliary Feedwater (AFW) Pump Rooms, which are Seismic Category I. All of the structural steel columns, beams, and roof trusses of the building have been designed as independent members and in accordance with the American Institute of Steel Construction "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," 1963 Edition. Two bridge cranes are located in the turbine-generator section of the building. The Units 1 and 2 turbine generators are mounted on their own concrete pedestals that project up through the building to the operating deck at Elevation 45'. [Reference 2, Section 5.6.3; Reference 7, Section 1.1.1]

As shown in Figure 3.3B-1, electrical ductbanks that run under the Turbine Building are connected between the AFW Pump Rooms and the Intake Structure. These ductbanks contain electrical conduits used for routing of the cables that power the Saltwater Pumps. The ductbanks are Seismic Category I and are constructed of reinforced concrete that encases the conduits. The ductbanks are sloped downward toward the Intake Structure to facilitate drainage of any groundwater that may seep into the conduits. [Reference 2, Section 5A.2.1; Reference 4]

The Turbine Building siding is classified as non-safety-related, while the siding clips that hold the siding in place are classified as SR. The siding clips are designed to fail when the differential pressure across the siding reaches a pre-determined pressure. This design allows the siding to "blow-off" and thereby provide venting after a postulated break of a main steam line in the Auxiliary Building or the Turbine Building. The venting function is provided in order to protect vital equipment and structures. [Reference 2, Page 10A.1-31; Reference 8, Page 77; Reference 9, Table 3S (Sheet 8)]

A wall at the end of the Main Steam Pipe Tunnel (separating the Auxiliary Building and the Turbine Building) is designed to fail at 0.5 psi *[pounds per square inch]* so that it will vent pressure into the Turbine Building if a main steam line breaks near the Main Steam Pipe Tunnel. The wall is also designed to fail when subjected to a hydraulic pressure of 3 feet of water from a main feedwater line rupture in the Main Steam Piping Area. The method of failure is that 4 retainer clips (2½ x 2½ x 11 gauge angles) on the Turbine Building side of the wall will fail plastically (i.e., go beyond the ultimate strength of the material) when a pressure of 0.5 psi or 3 feet of water is exerted on the wall from the Main Steam Pipe Tunnel side. Since the retainer clips are the controlling mechanism of failure, they are classified as SR. [Reference 2, Section 10A.1.20; Reference 8, Page 74]

For all major structures below finish grades, a heavy waterproofing membrane of 40 mils thickness is provided at the exposed face of the exterior walls and below the base slab. Rubber waterstops are also provided at all construction joints up to grade elevation. Subsurface drains are provided to lower the elevation of groundwater around the plant. [Reference 2, Section 5A.5]

The conceptual boundaries of the Turbine Building evaluation include the AFW Pump Rooms because they are Seismic Category I. As described in the CCNPP IPA Methodology, all CCNPP Category I structures are designated as SR; therefore, all Category I structures are screened as within the scope of license renewal. The Turbine Building evaluation included the AFW Pump Rooms and their associated structural components, but did not include commodity items such as component supports as discussed below. The electrical ductbanks that run under the Turbine Building between the AFW Pump Rooms and the Intake Structure are also included in the conceptual boundaries of this evaluation because they are Seismic Category I. In addition, the Turbine Building siding clips and retainer clips are within the scope of license renewal because they are SR. [Reference 1, Section 3.4; Reference 2, Sections 5.6.3 and 5A.2.1; Reference 3, Tables 1 and 2; Reference 9, Table 3S]

Component supports that are connected to the structural components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. Component supports are defined as the connection between a system, or component within a system, and a plant structural member. An example of a component support is the fixed base that supports a pump. The pump would be scoped with its respective system evaluation. The component support is the fixed base that connects the concrete equipment pad to the pump. The fixed base is scoped with the Component Supports Commodity Evaluation and the concrete equipment pad is scoped with the evaluation for the structure. If anchor bolts are used, there is overlap between the Component Supports Commodity Evaluation and the evaluation for the structural component. Evaluations for structural components considered the effects of aging caused by the surrounding environment, while the Component Supports Commodity Evaluation considered the effects of aging caused by the supported equipment (thermal expansion, rotating equipment, etc.) as well as the surrounding environment. Supports for structural components such as platform hangers are not "component supports" in this sense because any support for a structural component is itself a structural component and is included in the scope of its respective structure. [Reference 10, Section 1.1.1]

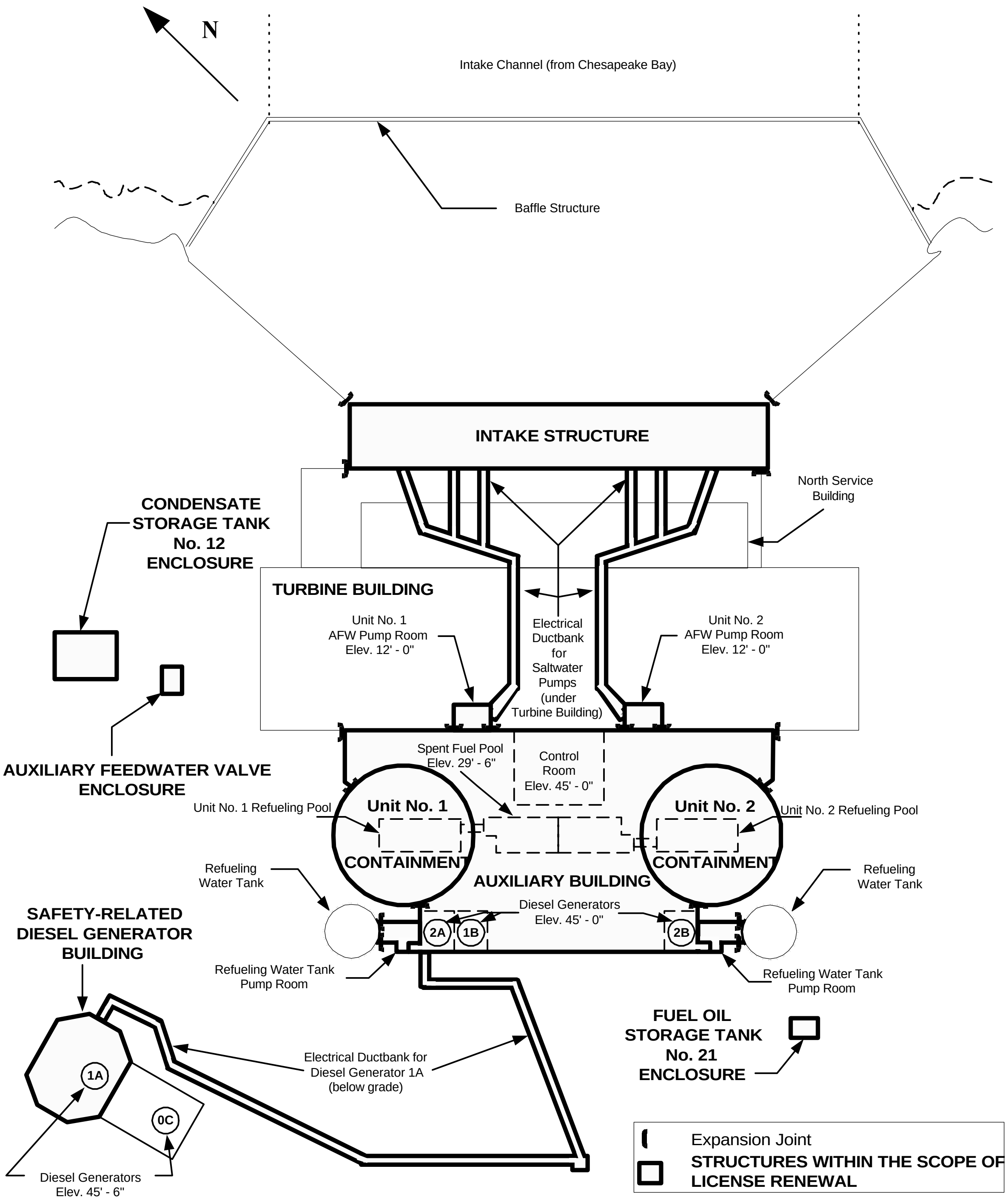

FIGURE 3.3B-1
CCNPP SITE STRUCTURES
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

Structure Scoping Results

The Turbine Building is within the scope of license renewal based on 10 CFR 54.4(a). Six out of seven of the generic structural functions listed above are applicable to the Turbine Building as shown in Table 3.3B-1. The intended functions for the Turbine Building were determined based on the requirements of §54.4(a)(1), §54.4(a)(2), and §54.4(a)(3), in accordance with CCNPP IPA Methodology Section 4.2.2. [Reference 7, Section 1.1.3; Reference 9, Table 1S]

TABLE 3.3B-1

INTENDED FUNCTIONS OF STRUCTURES

Function	Applicable to Turbine Building? *	Applicable 10 CFR 54.4(a) Criteria
1. Provide structural and/or functional support to SR equipment	Yes	§54.4(a)(1)
2. Provide shelter/protection to SR equipment	Yes	§54.4(a)(1)
3. Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated Design Basis Events	No	§54.4(a)(1)
4. Serve as a missile barrier (internal or external)	Yes	§54.4(a)(1)
5. Provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions	Yes	§54.4(a)(2)
6. Provide flood protection barrier (internal flooding event)	Yes	§54.4(a)(2)
7. Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant	Yes	§54.4(a)(3)

* Functions are shown as being applicable if they apply to any portion of the structure (e.g., AFW Pump Rooms.

Components Subject to AMR

As discussed above, the component level scoping process for structures utilized a generic list of structural component types. The generic list started with structural component types contained in industry technical reports addressing containment structures and other Category I structures. Other structural component types were added to the list to ensure completeness. Additionally, any structural component types that are unique to the particular structure being scoped, such as the prestressed tendons in the Containment and the sluice gates in the Intake Structure, are noted. These structural components were combined into four structural categories based on their design and materials as follows: [Reference 1, Section 4.2.3; Reference 9]

- Concrete Components;
- Structural Steel Components;
- Architectural Components; and
- Unique Components.

During the scoping process, those structural component types actually contained in the Turbine Building were identified. Within the four structural component categories, 24 structural component types were determined to contribute to at least one of the Turbine Building intended functions listed in Table 3.3B-1. Table 3.3B-2 lists these 24 structural component types and their associated intended functions. Structural component types that are part of the Turbine Building, but do not contribute to any of the intended functions of the structure, are not listed in the table. All of the structural component types that were identified as requiring AMR for the Turbine Building (except for the ductbanks, building siding clips, and retainer clips) are associated with the AFW Pump Rooms. [Reference 7, Table 2-1 and Appendix K, Section 2.2; Reference 9, Table 3S]

TABLE 3.3B-2

STRUCTURAL COMPONENT TYPES REQUIRING AMR FOR THE TURBINE BUILDING

Structural Component Type	Applicable Function(s)
Concrete (Including Reinforcing Steel)	
Walls	1, 2, 4, 6, 7
Ground Floor Slabs and Equipment Pads	1, 2, 4, 6, 7
Elevated Floor Slabs	1, 2, 6, 7
Cast-In-Place Anchors/Embedments*	1, 2, 6, 7
Ductbanks	1, 2
Grout	1, 2, 6, 7
Fluid Retaining Walls and Slabs	1, 2, 6, 7
Post-Installed Anchors*	4, 5
Structural Steel	
Beams*	1, 2, 7
Baseplates*	1, 2, 4, 5, 7
Floor Framing*	1, 2, 7
Platform Hangers*	5
Decking*	1, 2, 7
Jet Impingement Barriers*	4
Floor Grating*	5
Stairs and Ladders*	5
Architectural Components	
Building Siding Clips	2
Retainer Clips	2
Fire Doors, Jambs, and Hardware*	2, 6, 7
Access Doors, Jambs, and Hardware*	2, 6, 7
Caulking and Sealants	6, 7
Unique Components	
Watertight Doors*	2, 6, 7
Pipe Whip Restraints*	2
Pipe Encapsulations (See note below)	2

(*) Asterisk in "Structural Component Type" column indicates that the component type is included under the heading "Steel Components" in Table 3.3B-3.

(#) Numbers in "Applicable Function(s)" column correspond to the associated intended functions as listed in Table 3.3B-1.

Note: Pipe encapsulations are scoped as part of the enclosing structure but are evaluated for the effects of aging in the Main Steam AMR Report.

As discussed in the CCNPP IPA Methodology Section 5.4, all seven of the generic structural functions are considered to be passive. In addition, plant structural components are not normally subject to periodic replacement programs. Therefore, structural components are considered to be long-lived unless specific justification is provided to the contrary. Based on the above, all of the structural component types listed in Table 3.3B-2 are subject to AMR for the Turbine Building. [Reference 7, Section 3.0]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

3.3B.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the Turbine Building components is given in Table 3.3B-3, with plausible ARDMs identified by a check mark (✓) in the appropriate column. [Reference 7, Attachments 1 and 2, Appendices C, E, K, and O] For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components. Table 3.3B-3 also identifies the group to which each ARDM/device type combination belongs. Exceptions are noted where appropriate. The following groups have been selected for the Turbine Building:

Group 1: Includes caulking and sealants subject to weathering; and

Group 2: Includes steel components subject to corrosion.

TABLE 3.3B-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE TURBINE BUILDING STRUCTURE

Potential ARDMs	Concrete Walls	Ground Floor Slabs	Equipment Pads	Elevated Floor Slabs	Ductbanks	Grout	Fluid Retaining Walls and Slabs	Caulking and Sealants	Siding Clips and Retainer Clips	Steel Components*
Leaching of Calcium Hydroxide										
Aggressive Chemical Attack on Concrete										
Corrosion of Embedded Steel/Rebar										
Settlement										
Corrosion										✓(2)
Weathering								✓(1)		
Fatigue										

* - "Steel Components" represent all structural component types marked with an asterisk (*) in Table 3.3B-2

✓ - Indicates plausible ARDM determination

(#) - Indicates the group(s) in which the ARDM/component type combination is evaluated

Aging mechanisms that are not plausible are generally not discussed further in these BGE LRA sections, unless they are considered noteworthy. For the Turbine Building, settlement is considered noteworthy and is discussed below.

An industry technical report concluded that settlement is a potentially significant ARDM for Category I structures. Settlement occurs both during construction and after construction. The amount of settlement depends on the physical properties of the foundation material. These properties range from rock (with little or no settlement likely) to compacted soil (with some settlement expected). Settlement may occur during the design life of the structure from changes in environmental conditions, such as lowering of the groundwater table. Settlement can occur in two stages: elastic expansion and time-dependent settlement. Elastic expansion of the confined soil occurs due to excavation unloading and results in a slightly upward movement. During construction, the soil moves downward as load is applied. This elastic movement should be small and is complete when construction is completed. It has no effect on the structure and is not considered an aging mechanism. The excavation unloading and structural loading cause a small change in the void ratio of the soil. This change results in a small amount of time-dependent settlement. The settlement rate will decline after completion of construction. Concrete and steel structural members can be affected by differential settlement between supporting foundations, within a building, or between buildings. Severe settlement can cause misalignment of equipment and lead to overstress conditions within the structure. When buildings experience significant settlement, cracks in structural members, differential elevations of supporting members bridging between buildings, or both, may be visibly detected. Settlement was determined to be not plausible for the CCNPP Turbine Building based on the following site-specific justification: [Reference 7, Appendix J, Sections 1.0 and 2.5; Reference 11, Section 5.1]

- The foundation for Turbine Building is situated on an engineered soil structure consisting of compacted soil on top of the site's Miocene deposit. The Miocene soil is very dense to extremely dense and is capable of supporting loads on the order of 15,000 to 20,000 pounds per square foot (psf) with slight consolidation. The design contact pressure of the Turbine Building foundation is only 5000 psf. This contact pressure is about the same as the overburden pressure removed due to excavation. [Reference 2, Sections 2.7.3.2, 2.7.5, and 2.7.6.2; Reference 7, Appendix J, Section 2.5; Reference 12]

- Nuclear Regulatory Commission IE Circular No. 81-08 discusses operating experience at a number of plants with respect to insufficient compaction of foundation and backfill material during plant construction. The insufficient compaction resulted in excessive settlement of plant structures at a number of sites. The NRC recommended actions included verification that quality assurance and quality control measures, including procedures, test results, inspection personnel, and audits, were in effect during construction to assure that the soil was adequately compacted. The backfill supporting the CCNPP Turbine Building was placed and compacted to requirements for density, moisture, and layer thickness in accordance with the quality assurance provisions in a specification used during plant construction. A continuous program of soil testing during construction was used to assure compliance with the specification. The soil supporting the Turbine Building foundation was compacted to a density of 97 percent compaction based on the standard Proctor compaction method. [Reference 12; Reference 13, Sections 2.0, 4.0, and 5.0; Reference 14, Sections 2.0 and 10.0; Reference 15]

- The excavation for the Turbine Building was below the groundwater table. A permanent pipe drain system surrounding the plant was installed during plant construction to minimize fluctuation of the groundwater table, thus providing stable geological conditions. [Reference 2, Section 2.7.3.2; Reference 7, Appendix J, Sections 2.4 and 2.5]

- Since the Turbine Building is situated on an exceptionally dense soil, the structure tends to uniformly settle. Most of the predicted settlement is expected in terms of uniform settlement, which has no adverse effect on the structural components of the Turbine Building. Any differential settlement is expected to be small and have negligible effect on the Turbine Building structural components. [Reference 7, Appendix J, Section 2.4]

Based on the above, settlement was determined to be not plausible for any structural components of the Turbine Building. This conclusion is supported by a walkdown of the Turbine Building, performed in 1994, which found no indication of structural damage due to settlement. [Reference 7, Appendix J, Section 3.0]

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

Group 1 - (caulking and sealants subject to weathering) - Materials and Environment

Group 1 includes caulking and sealants subject to weathering. These structural components provide flood protection barriers (internal flooding event) and provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant. [Reference 7, Appendix O, Section 2.2

The material requirements for the caulking and sealants used during construction of CCNPP were governed by a construction specification. Specific manufacturers and brand names (or approved equals) were specified for different applications. [Reference 16]

The caulking and sealants located indoors will be subject to the ambient conditions within the Turbine Building. The Turbine Building ambient temperature is controlled by a plant heating and ventilation system as described in UFSAR Chapter 9. The caulking and sealants located outdoors will be subject to the temperature and humidity changes, rain, snow, etc. expected at the CCNPP site. [Reference 2, Section 9.8.2.4, Table 9-18; Reference 7, Appendix O, Section 2.1]

Group 1 - (caulking and sealants subject to weathering) - Aging Mechanism Effects

Caulking and sealants that are exposed to ambient conditions (indoor or outdoor) are susceptible to degradation due to weathering. Exposure to sunlight (ultraviolet exposure), changes in humidity, ozone cycles, temperature and pressure fluctuations, and snow, rain, or ice contribute to the weathering ARDM. The effects of weathering on most caulking and sealant materials are evidenced by a decrease in elasticity (drying out), an increase in hardness, and shrinkage. [Reference 7, Appendix O, Section 1.0]

Weathering was determined to be plausible for the Turbine Building caulking and sealants due to their exposure to the environmental conditions that contribute to this ARDM. [Reference 7, Appendix O, Sections 2.1 and 2.5]

This aging mechanism, if unmanaged, could eventually result in the caulking and sealants not being able to perform their intended functions under current licensing basis (CLB) conditions. Therefore, weathering was determined to be a plausible ARDM for which the aging effects must be managed for the Turbine Building caulking and sealants. [Reference 7, Appendix O, Section 2.3]

Group 1 - (caulking and sealants subject to weathering) - Methods to Manage Aging

Mitigation: Because weathering of caulking and sealants is affected by exposure to environmental conditions that are not feasible to control (e.g., light, heat, oxygen, ozone, water, radiation), there are no practical methods to mitigate its effects.

Discovery: Caulking and sealants degrade over time and should be replaced as needed. An inspection program that provides requirements and guidance for the identification, inspection, and maintenance of caulking and sealants can ensure that their condition is maintained at a level that allows them to perform their intended functions. An effective program will provide for baseline inspection, along with periodic future inspections at appropriate intervals, depending upon the degree of harshness of the environment the caulking or sealant is in. Items that are in a harsh exterior environment would be inspected more frequently. This program would involve visual inspection and probing to determine that the caulking or sealant is satisfactorily attached to the surface and is flexible.

Group 1 - (caulking and sealants subject to weathering) - Aging Management Programs

Mitigation: There are no CCNPP programs credited for mitigation of weathering.

Discovery: Caulking and sealants that perform a fire barrier function are managed under an existing program. The Penetration Fire Barrier Inspection Program, implemented through CCNPP Surveillance Test Procedure (STP), STP-F-592-1/2, is adequate to manage the effects of aging for caulking and sealants that function as fire barriers without modification. [Reference 7, Appendix O, Section 2.6].

The purpose of STP-F-592-1/2 is to provide instructions for visual inspection of fire barrier penetration seals in fire area boundaries that protect safe shutdown areas in Units 1 and 2. The scope of this procedure is to visually inspect the following type of fire barrier penetration seals for operability: [References 17 and 18, Sections 1.0 and 2.2]

- Electrical conduit and cable tray penetration seals;
- Heating, ventilating, and air conditioning duct penetration seals (ducts without dampers); and
- Mechanical pipe and expansion joint penetration seals.

Procedure STP-F-592-1/2 was developed based on CCNPP Technical Specifications 3.7.12 and 4.7.12.a, 10 CFR Part 50, Appendix R, the CCNPP Fire Protection Plan, NRC Generic Letter 86-10, and various plant drawings. [References 17 and 18, Section 3.1]

The procedure is currently performed at least once per 18 months in accordance with Technical Specification 4.7.12.a. The procedure requires that the fire barrier penetration seals be visually inspected to determine if they are operable based on specific criteria that were developed for each type of fire barrier component. In general, the procedure inspects the penetration seals for damage, cracking, voids, and proper installation. The procedure provides separate "failure criteria" and "repair criteria." The "failure criteria" are used to determine if the penetration seal is considered to be inoperable. The "repair criteria" are used to determine if the penetration seal is operable but in need of repair. [References 17 and 18, Sections 2.1 and 6.0, and Attachment A]

If a fire barrier penetration seal is determined to be inoperable based on the procedure criteria, plant personnel determine if actions are required in accordance with Technical Specification 3.7.12.a. In addition, any conditions adverse to quality discovered during the inspection are documented on Issue Reports in accordance with the CCNPP Corrective Actions Program. [References 17 and 18, Section 6.5 and Attachment B]

The Fire Protection Program at CCNPP (which includes STP-F-592-1/2) is subject to periodic internal assessment in accordance with the requirements in BGE's Quality Assurance Policy. Audits are required for the Fire Protection Program and implementing procedures every two years. In addition, an independent fire protection and loss prevention program inspection and audit utilizing either qualified offsite BGE personnel or an outside fire protection firm is also required every two years. The Quality Assurance Policy also requires an inspection and audit of the fire protection and loss prevention program by a qualified outside fire consultant at least once every three years. An audit and inspection performed in 1996 (using an outside consultant as well as BGE personnel) concluded that the CCNPP Fire Protection Program is providing a level of safety consistent with good fire protection practices and NRC regulatory criteria. The inspection included plant walkdowns of some of the fire barrier penetration seals. No age-related degradation issues for the seals were identified. [Reference 19, Section 1B.18]

The Fire Protection Program also undergoes periodic inspection by the NRC as part of their routine licensee assessment activities. An inspection of the program in 1994 included a review of procedure STP-F-592-1 and a plant tour that included inspection of some of the fire barrier penetrations. The NRC concluded that the Fire Protection Program complies with program requirements provided in the Technical Specifications and licensing documents. [References 20 and 21]

Operating experience related to this program has shown that aging is a minor contributor to fire barrier penetration seal failures at CCNPP. The greatest contributor to degradation of these seals is believed to be due to inadequacies in the original installation of the seal materials. For example, degraded seals have been found to be the result of incomplete installation of the seal material (i.e., openings left in the penetrations) or due to improper grout installation.

The corrective actions taken as a result of the Penetration Fire Barrier Inspection Program will ensure that the Turbine Building caulking and sealants that perform a fire barrier function will remain capable of performing their intended function under all CLB conditions.

Caulking and sealants that are not fire barriers are typically replaced upon identification of their degraded condition. Visual examinations of the caulking and sealants in the plant concluded that an inspection program was needed to adequately manage the aging of these architectural components. [Reference 7, Appendix O, Section 2.4]

For the caulking and sealants that do not perform a fire barrier function, a new CCNPP Caulking and Sealant Inspection Program will provide requirements and guidance for the identification, inspection frequencies, and acceptance criteria for caulking and sealant used in the Turbine Building to ensure that their condition is maintained at a level that allows them to perform their intended functions. The new program will establish acceptance criteria and require a baseline inspection to determine the material condition of the caulking and sealants for the Turbine Building. If unacceptable degradation exists, corrective actions will be taken. A technical basis will be developed for determining the periodicity of future inspections. [Reference 7, Attachment 8]

Group 1 - (caulking and sealants subject to weathering) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to weathering of caulking and sealants:

- The caulking and sealants provide flood protection barriers (internal flooding event) and provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant.
- Weathering was determined to be a plausible ARDM for the caulking and sealants. This ARDM, if unmanaged, could eventually result in the caulking and sealants not being able to perform their intended functions under CLB conditions.
- For caulking and sealants that function as fire barriers, the Penetration Fire Barrier Inspection Program performs periodic visual inspections of fire barrier penetration seals, and contains acceptance criteria that ensure corrective actions will be taken such that the fire barrier intended function will be maintained.
- For caulking and sealants that do not perform a fire barrier function, a new Caulking and Sealants Inspection Program will conduct inspections to detect age-related degradation, and will contain acceptance criteria that ensure corrective actions will be taken such that the intended functions will be maintained.

Therefore, there is reasonable assurance that the effects of weathering will be adequately managed such that the caulking and sealants will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 2 - (steel components subject to corrosion) - Materials and Environment

Group 2 includes the Turbine Building steel components marked with an asterisk in Table 3.3B-2. These components are all subject to corrosion. They each contribute to one or more of the various Turbine Building intended functions as shown in Table 3.3B-2. [Reference 7, Appendix K, Section 2.2]

Since corrosion was recognized as a potential degradation mechanism for all structural steel components of the Turbine Building, its effects were considered in the original design. As a result, all exposed structural steel surfaces in the Turbine Building, except grating and metal decking, which are galvanized steel, were shop-painted or field-painted during plant construction. [Reference 7, Appendix K, Section 2.4]

The steel components located indoors will be subject to the ambient conditions within the Turbine Building. The Turbine Building ambient temperature is controlled by a plant heating and ventilation system as described in UFSAR Chapter 9. The steel components located outdoors will be subject to the temperature and humidity changes, rain, snow, etc. expected at the CCNPP site. [Reference 2, Section 9.8.2.4, Table 9-18]

Group 2 - (steel components subject to corrosion) - Aging Mechanism Effects

Steel corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. Initially, the exposed steel surface reacts with oxygen and moisture to form an oxide film as rust. Once the protective oxide film has been formed and if it is not disturbed by erosion, alternating wetting and drying, or other surface actions, the oxidation rate will diminish rapidly with time. Chlorides, either from saltwater, the atmosphere, or groundwater, increase the rate of corrosion by increasing the electrochemical activity. If steel is in contact with another metal that is more noble in the galvanic series, corrosion of the steel may accelerate. [Reference 7, Appendix K, Section 1.0]

Corrosion products such as hydrated oxides of iron (rust) form on exposed, unprotected surfaces of the steel and are readily visible. The affected surface may degrade to such an extent that visible perforation may occur. In the case of exposed surfaces of steel with protective coatings, corrosion may cause the protective coatings to lose their ability to adhere to the corroding surface. In this case, damage to the coatings can be visually detected well in advance of significant degradation of the steel. [Reference 7, Appendix K, Section 1.0]

An inspection of the AFW Pump Rooms, which are located inside the Turbine Building, was performed in 1994. The interior and exterior of the pump rooms were inspected and minor areas of rust on steel components were identified. [Reference 7, Attachment 7]

This aging mechanism, if unmanaged, could eventually result in the steel components not being able to perform their intended functions under CLB conditions. Therefore, corrosion was determined to be a plausible ARDM for which the aging effects must be managed for the Turbine Building steel components. [Reference 7, Appendix K, Section 2.3]

Group 2 - (steel components subject to corrosion) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of the steel components to an aggressive environment and protecting the external surfaces with paint or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces.

Discovery: The effects of general corrosion/oxidation of steel are detectable by visual inspection. A visual examination by a person familiar with the components can be used to determine general mechanical and structural condition and check for rust. Observing that significant degradation of protective coatings has not occurred is an effective method to ensure that corrosion has not affected the intended function of the structural component. Since the coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition that triggers corrective action before the occurrence of corrosion that would affect the components' ability to perform their intended functions. The degradation of the protective coating that does occur can be discovered and monitored by periodically inspecting the steel structural components. Corrective action for failed protective coatings and any actual metal degradation can be carried out as necessary. [Reference 7, Appendix K, Section 3.0]

Group 2 - (steel components subject to corrosion) - Aging Management Programs

Mitigation: No programs are credited for mitigation. The exposed surfaces of structural steel components are covered by protective coatings that mitigate the effects of corrosion. The discovery programs discussed below verify that the protective coatings are maintained.

Discovery: Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of corrosion of steel (or conditions that would accelerate corrosion, such as pooled water) for the Turbine Building by performance of visual inspections during plant walkdowns. The purpose of the program is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. This program is applicable to the Turbine Building steel components. [Reference 22, Section 1.1]

Under this program, responsible personnel perform periodic walkdowns of their assigned structures and systems. Walkdowns may also be performed as required for reasons such as: material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when the system is initially pressurized, energized, or placed in service); and as required for plant modifications. [Reference 22, Section 5.1]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any abnormal or degraded condition will be identified, documented, and corrective actions taken before the condition proceeds to failure of the structures, systems, and components to perform their intended functions. Conditions adverse to quality are documented and resolved by the CCNPP Corrective Actions Program. [Reference 22, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The program provides guidance for identification of specific types of degradation or conditions when performing the walkdowns. Inspection items related to aging management include the following: [Reference 22, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

A structure performance assessment is currently required for Category I structures at CCNPP at least once every six years. The assessment includes a review of each structural component that could degrade the overall performance of the structure. The program will be modified to add guidance regarding approval authority for significant departures from the walkdown scope/schedule specified. [Reference 22, Section 5.3]

The corrective actions taken as a result of the program described above will ensure that the Turbine Building steel components will remain capable of performing their intended functions under all CLB conditions.

Group 2 - (steel components subject to corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of steel components for the Turbine Building:

- The Turbine Building steel components contribute to one or more of the various Turbine Building intended functions as shown in Table 3.3B-2.

- The steel components are subject to corrosion due to the normal ambient environmental conditions. This ARDM, if unmanaged, could eventually result in the steel components not being able to perform their intended functions under CLB conditions.
- Corrosion is mitigated by applying protective coatings to the steel components and by periodically examining the components for degradation of that coating or conditions that could accelerate degradation.
- Calvert Cliffs procedure MN-1-319 provides for periodic visual inspections of these components during walkdowns of the Turbine Building. If any degradation is found, the appropriate corrective actions are taken to ensure that the intended functions will be maintained.

Therefore, there is reasonable assurance that the effects of aging due to corrosion of steel will be managed such that the steel components of the Turbine Building will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

3.3B.3 Conclusion

The aging management programs discussed for the Turbine Building are listed in the following table. These programs are (or will be for new programs) administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the Turbine Building will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 3.3B-4

LIST OF AGING MANAGEMENT PROGRAMS FOR THE TURBINE BUILDING STRUCTURE

	Program	Credited As
Existing	CCNPP Technical Procedure STP-F-592-1/2, "Penetration Fire Barrier Inspection"	Discovery of weathering effects for caulking and sealants that function as fire barriers for the Turbine Building. (Group 1)
Modified	CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns"	Discovery of corrosion effects for steel components in the Turbine Building. (Group 2)
New	Caulking and Sealant Inspection Program	Discovery of weathering effects for caulking and sealants that do not function as fire barriers for the Turbine Building. (Group 1)

3.3B.4 References

1. CCNPP "Integrated Plant Assessment Methodology," Revision 1, January 11, 1996
2. CCNPP Updated Final Safety Analysis Report, Revision 21
3. CCNPP "Life Cycle Management System and Structure Screening Results," Revision 5, September 10, 1997
4. CCNPP Drawing 61230, "Salt Water Systems Underground Ducts Plan and Sections," Revision 6, October 15, 1990
5. CCNPP Drawing 63874SH0004, "SR Ductbank Under West Plant Road Plan," Revision 0, April 4, 1995
6. CCNPP Drawing 63874SH0005, "Underground Conduit West of Turbine Building Plan," Revision 0, July 15, 1996
7. CCNPP "Aging Management Review Report for the Turbine Building Structure," Revision 3, February 12, 1997
8. CCNPP Engineering Standard ES-011, "System, Structure and Component (SSC) Evaluation," Revision 2, September 15, 1997
9. CCNPP "Component Level Scoping Results for the Turbine Building Structure," Revision 2, February 12, 1997
10. CCNPP "Aging Management Review Report for Component Supports," Revision 3, February 4, 1997
11. Electric Power Research Institute Report TR-103842, "Class I Structures License Renewal Industry Report," Revision 1, July 1994
12. CCNPP Drawing 60119, "Compacted Fill Areas," Revision 0, April 24, 1970
13. Bechtel Specification No. 6750-C-4A, "Specification for Placement and Control of Compacted Fill - CCNPP Units 1 and 2," Revision 3, August 7, 1970
14. Bechtel Specification No. 6750-C-11-B, "Specification for Testing of Concrete, Reinforcement and Soil - CCNPP Units 1 and 2," Revision 1, May 9, 1975
15. NRC IE Circular No. 81-08, "Foundation Materials," May 29, 1981
16. CCNPP Specification A-0010 (Bechtel Specification No. 6750-A-10), "Specification for Furnishing, Delivery and Application of the Caulking and Sealants," Revision 1, March 3, 1971
17. CCNPP Technical Procedure STP-F-592-1, "Penetration Fire Barrier Inspection," Revision 3, August 26, 1997
18. CCNPP Technical Procedure STP-F-592-2, "Penetration Fire Barrier Inspection," Revision 2, August 26, 1997
19. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48, March 28, 1997
20. Letter from Mr. L. T. Doerflein (NRC) to Mr. C. H. Cruse (BGE), dated May 14, 1997, "Plant Performance Review (PPR) - Calvert Cliffs"

21. Letter from Mr. J. T. Trapp (NRC) to Mr. R. E. Denton (BGE), dated May 6, 1994, "Combined Inspection Report Nos. 50-317/94-15 and 50-318/94-15"

22. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0, September 16, 1997

3.3C Intake Structure

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Intake Structure. The Intake Structure was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

3.3C.1 Scoping

The system level scoping process defines conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Systems and structures that are within the scope of license renewal are then scoped further on a component level. [Reference 1, Section 3.0]

The component level scoping process for systems is described in Section 4.1 of the IPA Methodology, and the component level scoping process for structures is described in Section 4.2 of the methodology. Components with unique equipment identifiers in the site equipment database are scoped using the component level scoping process for systems. Structural components such as walls do not have unique equipment identifiers. Therefore, the component level scoping process for structures utilizes a generic listing of structural component types. [Reference 1, Section 4.0]

The CCNPP Intake Structure contains system-type components with unique equipment identifiers in the site equipment database, as well as structural-type components that do not have unique equipment identifiers. The system-type components include a variety of non-safety-related mechanical, electrical, and instrumentation components associated with equipment such as the traveling screens and screen wash pumps. The components with Intake Structure unique equipment identifiers were scoped using the component level scoping process for systems, and it was determined that none of these components are within the scope of license renewal. The component level scoping results for the structural-type components are discussed below. [Reference 2]

The component level scoping process for structures identifies structural-type components as being within the scope of license renewal if they perform one or more of the following generic structural functions: [Reference 1, Section 4.2.2]

- Provide structural and/or functional support to safety-related (SR) equipment;
- Provide shelter/protection to SR equipment;
- Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated Design Basis Events;
- Serve as a missile barrier (internal or external);
- Provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions;
- Provide flood protection barrier (internal flooding event); and
- Provide a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.

The remainder of Section 3.3C.1 provides a description of the Intake Structure including the conceptual boundaries from the system level scoping results, the results of the component level scoping, and the results of the scoping to determine the components subject to aging management review (AMR).

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

Structure Description/Conceptual Boundaries

Figure 3.3C-1 is a simplified layout of site structures showing the structures that are within the scope of license renewal, including the Intake Structure. The CCNPP site arrangement consists of numerous structures as shown on Figure 1-2 of the CCNPP Updated Final Safety Analysis Report (UFSAR). Design features of the CCNPP structures are discussed in UFSAR Chapter 5. [Reference 3; Reference 4, Table 2; References 5, 6, and 7]

The Intake Structure is situated to the east of the main plant between the North Service Building and the Chesapeake Bay shoreline. The structure houses twelve circulating water pumps that supply water from the Chesapeake Bay to the condensers, and six saltwater pumps that provide cooling water to various plant equipment. Trash racks and traveling screens are provided to protect the condensers from foreign bodies present in the bay water. Running the full length of the structure is a gantry crane having a lifting capacity of 35 tons. [Reference 3, Figure 1-2, Section 5.6.2.1, Reference 8, Section 1.1.1]

The Intake Structure is approximately 90' (width) x 385' (length) and is constructed primarily of reinforced concrete. The foundation slab varies in elevation from -26'-0" to -14'-3". The total effective load due to the structure is approximately 42,000 tons. As a result, net soil pressures due to the structure are approximately 2500 pounds per square foot (psf). [Reference 3, Sections 2.7.5.1 and 5.6.2.1]

For all major structures below finish grades, a heavy waterproofing membrane of 40 mils thickness is provided at the exposed face of the exterior walls and below the base slab. Rubber waterstops are also provided at all construction joints up to grade elevation. Subsurface drains are provided to lower the elevation of groundwater around the plant. [Reference 3, Section 5A.5]

Since the Intake Structure houses the saltwater pumps that are essential for safe shutdown of CCNPP, the structure was designed as a Category I structure for seismic, tornado, and hurricane conditions. The Intake Structure is also designed to protect the saltwater pump motors from external flooding due to the maximum hypothetical hurricane tide and storm surges, including wave action. The Intake Structure design loads and conditions are shown in UFSAR Table 5-7 and UFSAR Section 5A.5. [Reference 3, Sections 2.8.3.6, 5.6.2.2, and 5A.5]

The structure is designed in accordance with American Concrete Institute (ACI) standards and the structural steel with American Institute of Steel Construction standards. The total length of the structure is divided into three sections above the base slab by two expansion joints. The high level roof at Elevation 28'-6" is comprised of a reinforced concrete slab supported on a structural steel frame. Within this roof are access covers to each of the saltwater and circulating water pumps. [Reference 3, Section 5.6.2.2]

The conceptual boundaries of this evaluation include the Intake Structure and all of its structural components such as foundations, walls, slabs, and steel beams. Component supports that are connected to the structural components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. Component supports are defined as the connection between a system, or component within a system, and a plant structural member. An example of a component support is the fixed base that supports a pump. The pump would be scoped with its respective system evaluation. The component support is the fixed base that connects the concrete equipment pad to the pump. The fixed base is scoped with the Component Supports Commodity Evaluation and the concrete equipment pad is scoped with the evaluation for the structure. If anchor bolts are used, there is overlap between the Component Supports Commodity Evaluation and the evaluation for the structural component. Evaluations for structural components considered the effects of aging caused by the surrounding environment, while the Component Supports Commodity Evaluation considered the effects of aging caused by the supported equipment (thermal expansion, rotating equipment, etc.), as well as the surrounding environment. Supports for structural components such as platform hangers are not "component supports" in this sense because any support for a structural component is itself a structural component and is included in the scope of its respective structure. [Reference 9, Section 1.1.1]

Cranes and fuel handling equipment that are connected to structures are evaluated for the effects of aging in the Cranes & Fuel Handling Commodity Evaluation in Section 3.2 of the BGE LRA. The Intake Structure Gantry Crane rails, girders, and other structural support members were evaluated in the Cranes and Fuel Handling Commodity Evaluation and are not included in this section.

As shown in Figure 3.3C-1, electrical ductbanks that run under the Turbine Building are connected between the Auxiliary Feedwater Pump Rooms and the Intake Structure. The ductbanks are Seismic Category I and are constructed of reinforced concrete. These ductbanks contain electrical conduits used for routing of the cables that power the saltwater pumps. The conduits in the ductbank connect to electrical pull boxes that are mounted on the west wall of the Intake Structure. These boxes provided a convenient pull point during construction for the saltwater pump motor cables. The pull boxes have experienced significant corrosion due to groundwater that drains into them through the conduits. The pull boxes are not within the scope of license renewal since they do not perform any intended functions as described in 10 CFR 54.4(a). The water leakage into the pull boxes is considered normal and is not considered a safety concern since the cables for the saltwater pump motors are suitable for submerged operation. The ductbanks are sloped downward toward the Intake Structure, and the pull boxes are provided with weep holes to facilitate drainage of the conduits. The ductbanks are evaluated for the effects of aging in the Turbine Building Structure Evaluation in Section 3.3B of the BGE LRA. The cables are evaluated for the effects of aging in the Cables Commodity Evaluation in Section 6.1 of the BGE LRA. [Reference 3, Section 5A.2.1; Page 9.5-29; Reference 5]

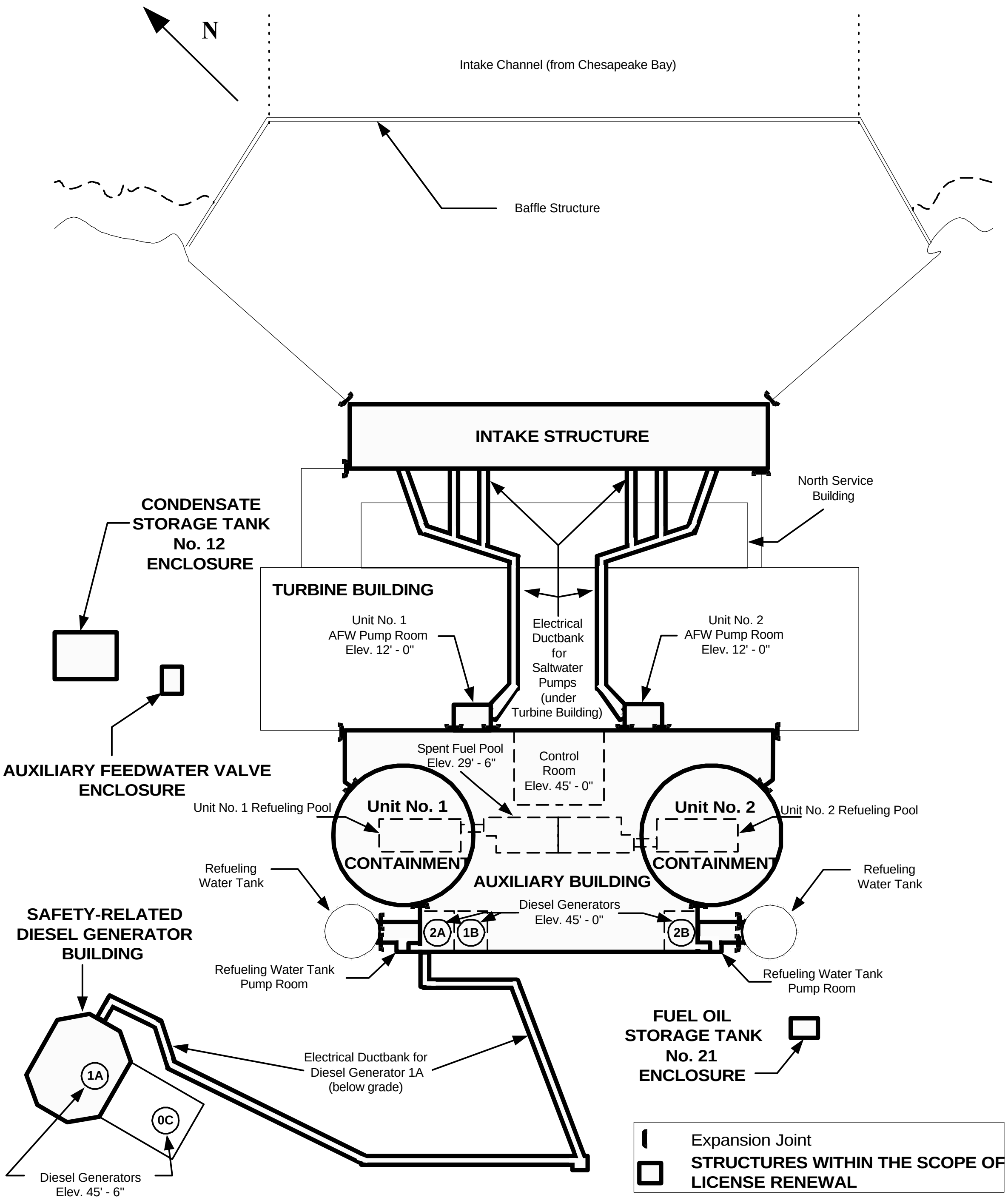

FIGURE 3.3C-1
CCNPP SITE STRUCTURES
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

Structure Scoping Results

The Intake Structure is in the scope of license renewal based on 10 CFR 54.4(a). Six out of seven of the generic structural functions listed above are applicable to the Intake Structure as shown in Table 3.3C-1. The intended functions for the Intake Structure were determined based on the requirements of §54.4(a)(1), §54.4(a)(2), and §54.4(a)(3), in accordance with CCNPP IPA Methodology Section 4.2.2. [Reference 2, Table 1S; Reference 8, Section 1.1.3]

TABLE 3.3C-1

INTENDED FUNCTIONS OF STRUCTURES

Function	Applicable to Intake Structure?	Applicable 10 CFR 54.4(a) Criteria
1. Provide structural and/or functional support to SR equipment	Yes	§54.4(a)(1)
2. Provide shelter/protection to SR equipment	Yes	§54.4(a)(1)
3. Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated Design Basis Events	No	§54.4(a)(1)
4. Serve as a missile barrier (internal or external)	Yes	§54.4(a)(1)
5. Provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions	Yes	§54.4(a)(2)
6. Provide flood protection barrier (internal flooding event)	Yes	§54.4(a)(2)
7. Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant	Yes	§54.4(a)(3)

Components Subject to AMR

As discussed above, the component level scoping process for structures utilized a generic list of structural component types. The generic list started with structural component types contained in industry technical reports addressing containment structures and other Category I structures. Other structural component types were added to the list to ensure completeness. Additionally, any structural component types that are unique to the particular structure being scoped, such as the prestressed tendons in the Containment and the sluice gates in the Intake Structure, are noted. These structural components were combined into four structural categories based on their design and materials as follows: [Reference 1, Section 4.2.3; Reference 2]

- Concrete Components;
- Structural Steel Components;
- Architectural Components; and
- Unique Components.

During the scoping process, those structural component types actually contained in the Intake Structure were identified. Within the four structural component categories, twenty-seven structural component types were determined to contribute to at least one of the Intake Structure intended functions listed in Table 3.3C-1. Table 3.3C-2 lists these 27 structural component types and their associated intended functions. Structural component types that are part of the Intake Structure, but do not contribute to any of the intended functions of the structure, are not listed in the table. [Reference 2, Table 3S; Reference 8, Table 2-1]

TABLE 3.3C-2

STRUCTURAL COMPONENT TYPES REQUIRING AMR

FOR THE INTAKE STRUCTURE

Structural Component Type	Applicable Function(s)
Concrete (Including Reinforcing Steel)	
Foundations (Footings, beams, and mats)	1, 2
Columns	1, 2, 4, 7
Walls	1, 2, 4, 7
Beams	2, 4
Ground Floor Slabs and Equipment Pads	1, 2
Elevated Floor Slabs	1, 2
Roof Slabs	2
Cast-In-Place Anchors/Embedments*	1, 2, 6, 7
Grout	1, 2
Fluid-retaining Walls and Slabs	1, 2, 6
Post-Installed Anchors*	2, 5
Structural Steel	
Beams*	1, 2
Baseplates*	1, 5
Floor Framing*	1, 5
Roof Framing*	2
Bracing*	2, 5
Platform Hangers*	5
Decking*	2
Floor Grating*	5
Checkered Plate*	2
Stairs and Ladders*	5
Architectural Components	
Fire Doors, Jambs, and Hardware*	2, 7
Access Doors, Jambs, and Hardware*	2
Caulking and Sealants	6, 7
Unique Components	
Watertight Doors*	2, 6
Sluice Gates	1
Expansion Joints	2, 7

(*) Asterisk in "Structural Component Type" column indicates that the component type is included under the heading "Steel Components" in Table 3.3C-3.

(#) Numbers in "Applicable Function(s)" column correspond to the associated intended functions as listed in Table 3.3C-1.

As discussed in IPA Methodology Section 5.4, all seven of the generic structural functions are considered to be passive. In addition, plant structural components are not normally subject to periodic replacement programs. Therefore, structural components are considered to be long-lived unless specific justification is provided to the contrary. Based on the above, all of the structural component types listed in Table 3.3C-2 are subject to AMR for the Intake Structure. [Reference 8, Section 3.0]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

3.3C.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the Intake Structure components is given in Table 3.3C-3, with plausible ARDMs identified by a check mark (✓) in the appropriate column. [Reference 8, Attachments 1 and 2, Appendices C, E, K, and O] For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components. Table 3.3C-3 also identifies the group to which each ARDM/device type combination belongs. Exceptions are noted where appropriate. The following groups have been selected for the Intake Structure:

Group 1: Includes caulking, sealants, and expansion joints subject to weathering;

Group 2: Includes fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel/rebar;

Group 3: Includes steel components subject to corrosion; and

Group 4: Includes sluice gates subject to corrosion.

TABLE 3.3C-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE INTAKE STRUCTURE

Potential ARDMs	Foundations	Concrete Columns, Walls, and Beams	Ground Floor Slabs and Equipment Pads	Elevated Floor Slabs	Roof Slabs	Grout	Fluid-Retaining Walls and Slabs	Caulking and Sealants	Expansion Joints	Steel Components*	Sluice Gates
Freeze-Thaw											
Leaching of Calcium Hydroxide											
Aggressive Chemical Attack on Concrete							✓(2)				
Corrosion of Embedded Steel/Rebar							✓(2)				
Abrasion and Cavitation											
Settlement											
Corrosion										✓(3)**	✓(4)**
Weathering								✓(1)	✓(1)		
Fatigue											

* - "Steel Components" represent all structural component types marked with an asterisk (*) in Table 3.3C-2

** - Group 3 components are subject to general corrosion. Group 4 components are subject to crevice corrosion, microbiologically-induced corrosion (MIC), and pitting.

✓ - Indicates plausible ARDM determination

(#) - Indicates the group(s) in which the ARDM/component type combination is evaluated

Aging mechanisms that are not plausible are generally not discussed further in these BGE LRA sections, unless they are considered noteworthy. For the Intake Structure, settlement is considered noteworthy and is discussed below.

An industry technical report concluded that settlement is a potentially significant ARDM for Category I structures. Settlement occurs both during construction and after construction. The amount of settlement depends on the physical properties of the foundation material. These properties range from rock (with little or no settlement likely) to compacted soil (with some settlement expected). Settlement may occur during the design life of the structure from changes in environmental conditions, such as lowering of the groundwater table. Settlement can occur in two stages: elastic expansion and time-dependent settlement. Elastic expansion of the confined soil occurs due to excavation unloading and results in a slightly upward movement. During construction, the soil moves downward as load is applied. This elastic movement should be small and is complete when construction is completed. It has no effect on the structure and is not considered an aging mechanism. The excavation unloading and structural loading cause a small change in the void ratio of the soil. This change results in a small amount of time-dependent settlement. The settlement rate will decline after completion of construction. Concrete and steel structural members can be affected by differential settlement between supporting foundations, within a building, or between buildings. Severe settlement can cause misalignment of equipment and lead to overstress conditions within the structure. When buildings experience significant settlement, cracks in structural members, differential elevations of supporting members bridging between buildings, or both may be visibly detected. Settlement was determined to be not plausible for the CCNPP Intake Structure based on the following site-specific justification: [Reference 8, Appendix J, Sections 1.0 and 2.5; Reference 10, Section 5.1]

- The basemat elevation of the Intake Structure is approximately 110 feet below the original ground elevation. The basemat is situated on Miocene soil, which is exceptionally dense and will support heavy foundation loads. The ultimate bearing capacity of the foundation strata is in excess of 80,000 psf, and the allowable bearing capacity is 15,000 psf. The design contact pressure of the Intake Structure foundation is only 2500 psf. This contact pressure is only 23% of the overburden pressure removed due to excavation. [Reference 8, Appendix J, Section 2.1]
- In addition to soil bearing capacity, settlement was also investigated in the design of the Intake Structure. A maximum post-construction settlement of 1/2 inch was predicted in the original Intake Structure design. Since the Intake Structure is situated on an exceptionally dense soil, the structure tends to uniformly settle. Most of the predicted 1/2-inch settlement is in terms of uniform settlement, which has no adverse effect on the structural components of the Intake Structure. A small fraction of the 1/2-inch settlement will be in terms of differential settlement. It is so small that the effect on the structural components is negligible. [Reference 3, Section 2.7.6.2; Reference 8, Appendix J, Section 2.4]

Based on the above, settlement was determined to be not plausible for any structural components of the Intake Structure. This conclusion is supported by a walkdown of the Intake Structure, performed in 1994, which found no indication of structural damage due to settlement. [Reference 8, Appendix J, Section 3.0]

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

Group 1 - (caulking, sealants, and expansion joints subject to weathering) - Materials and Environment

Group 1 includes caulking, sealants, and expansion joints subject to weathering. These structural components provide Intake Structure intended functions as shown in Table 3.3C-2. [Reference 8, Appendix O, Section 2.2]

The material requirements for the caulking, sealants, and expansion joints used during construction of CCNPP were governed by construction specifications. Specific manufacturers' and brand names (or approved equals) were specified for different applications. [References 11 and 12]

The caulking, sealants, and expansion joints located indoors will be subject to the ambient conditions within the Intake Structure. The Intake Structure ambient temperature is controlled by a plant ventilation system as described in UFSAR Chapter 9. The caulking, sealants, and expansion joints located outdoors will be subject to the temperature and humidity changes, rain, snow, etc. expected at the CCNPP site. [Reference 3, Section 9.8.2.6, Table 9-18; Reference 8, Appendix O, Section 2.1]

Group 1 - (caulking, sealants, and expansion joints subject to weathering) - Aging Mechanism Effects

Caulking, sealants, and expansion joints that are exposed to ambient conditions (indoor or outdoor) are susceptible to degradation due to weathering. Exposure to sunlight (ultraviolet exposure), changes in humidity, ozone cycles, temperature and pressure fluctuations, and snow, rain, or ice contribute to the weathering ARDM. The effects of weathering on most caulking, sealant, and expansion joint materials are evidenced by a decrease in elasticity (drying out), an increase in hardness, and shrinkage. [Reference 8, Appendix O, Section 1.0]

Weathering was determined to be plausible for the Intake Structure caulking, sealants, and expansion joints due to their exposure to the environmental conditions that contribute to this ARDM. [Reference 8, Appendix O, Sections 2.1 and 2.5]

Expansion joints that run along the Intake Structure floor have experienced age-related degradation in the past. The degradation allowed water seepage up through the joints. The affected joints were subsequently repaired using approved sealant materials.

This aging mechanism, if unmanaged, could eventually result in the caulking, sealants, and expansion joints not being able to perform their intended functions under current licensing basis (CLB) conditions. Therefore, weathering was determined to be a plausible ARDM for which the aging effects must be managed for the Intake Structure caulking, sealants, and expansion joints. [Reference 8, Appendix O, Section 2.3]

Group 1 - (caulking, sealants, and expansion joints subject to weathering) - Methods to Manage Aging

Mitigation: Because weathering of caulking, sealants, and expansion joints is affected by exposure to environmental conditions that are not feasible to control (e.g., light, heat, oxygen, ozone, water, radiation), there are no practical methods to mitigate its effects.

Discovery: Caulking, sealants, and expansion joints degrade over time and should be replaced as needed. An inspection program that provides requirements and guidance for the identification, inspection, and maintenance of caulking, sealants, and expansion joints can ensure that their condition is maintained at a level that allows them to perform their intended functions. An effective program will provide for baseline inspection along with periodic future inspections at appropriate intervals depending upon the degree of harshness of the environment of the caulking, sealant, or expansion joint. Items that are in a harsh exterior environment would be inspected more frequently. This program would involve visual inspection and probing to determine that the caulking, sealant, or expansion joint is satisfactorily attached to the surface and is flexible.

Group 1 - (caulking, sealants, and expansion joints subject to weathering) - Aging Management Programs

Mitigation: There are no CCNPP programs credited for mitigation of weathering.

Discovery: Caulking, sealants, and expansion joints that perform a fire barrier function are managed under an existing program. The Penetration Fire Barrier Inspection Program, implemented through a CCNPP Surveillance Test Procedure (STP), STP-F-592-1/2, is adequate to manage the effects of aging for caulking, sealants, and expansion joints that function as fire barriers without modification. [Reference 8, Appendix O, Section 2.6].

The purpose of STP-F-592-1/2 is to provide instructions for visual inspection of fire barrier penetration seals in fire area boundaries that protect safe shutdown areas in Units 1 and 2. The scope of this procedure is to visually inspect the following type of fire barrier penetration seals for operability: [References 13 and 14, Sections 1.0 and 2.2]

- Electrical conduit and cable tray penetration seals;
- Heating, ventilation, and air conditioning duct penetration seals (ducts without dampers); and
- Mechanical pipe and expansion joint penetration seals.

Procedure STP-F-592-1/2 was developed based on CCNPP Technical Specifications 3.7.12 and 4.7.12.a, 10 CFR Part 50 Appendix R, the CCNPP Fire Protection Plan, NRC Generic Letter 86-10, and various plant drawings. [References 13 and 14, Section 3.1]

The procedure is currently performed at least once per 18 months in accordance with Technical Specification 4.7.12.a. The procedure requires that the fire barrier penetration seals be visually inspected to determine if they are operable based on specific criteria that were developed for each type of fire barrier component. In general, the procedure inspects the penetration seals for damage, cracking, voids, and proper installation. The procedure provides separate "failure criteria" and "repair criteria." The "failure criteria" are used to determine if the penetration seal is considered to be inoperable. The "repair criteria" are used to determine if the penetration seal is operable but in need of repair. [References 13 and 14, Sections 2.1 and 6.0, and Attachment A]

If a fire barrier penetration seal is determined to be inoperable based on the procedure criteria, plant personnel determine if actions are required in accordance with Technical Specification 3.7.12.a. In addition, any conditions adverse to quality discovered during the inspection are documented on Issue

Reports in accordance with the CCNPP Corrective Actions Program. [References 13 and 14, Section 6.5 and Attachment B]

The Fire Protection Program at CCNPP (which includes STP-F-592-1/2) is subject to periodic internal assessment in accordance with the requirements in BGE's Quality Assurance Policy. Audits are required for the Fire Protection Program and implementing procedures every two years. In addition, an independent fire protection and loss prevention program inspection and audit utilizing either qualified offsite BGE personnel or an outside fire protection firm is also required every two years. The Quality Assurance Policy also requires an inspection and audit of the fire protection and loss prevention program by a qualified outside fire consultant at least once every three years. An audit and inspection performed in 1996 (using an outside consultant as well as BGE personnel) concluded that the CCNPP Fire Protection Program is providing a level of safety consistent with good fire protection practices and NRC regulatory criteria. The inspection included plant walkdowns of some of the fire barrier penetration seals. No age-related degradation issues for the seals were identified. [Reference 15, Section 1B.18]

The Fire Protection Program also undergoes periodic inspection by the NRC as part of their routine licensee assessment activities. An inspection of the program in 1994 included a review of procedure STP-F-592-1 and a plant tour that included inspection of some of the fire barrier penetrations. The NRC concluded that the Fire Protection Program complies with program requirements provided in the Technical Specifications and licensing documents. [References 16 and 17]

Operating experience related to this program has shown that aging is a minor contributor to fire barrier penetration seal failures at CCNPP. The greatest contributor to degradation of these seals is believed to be due to inadequacies in the original installation of the seal materials. For example, degraded seals have been found to be the result of incomplete installation of the seal material (i.e., openings left in the penetrations) or due to improper grout installation.

The corrective actions taken as a result of the Penetration Fire Barrier Inspection Program will ensure that the Intake Structure caulking, sealants, and expansion joints that perform a fire barrier function will remain capable of performing their intended function under all CLB conditions.

Caulking, sealants, and expansion joints that are not fire barriers are typically replaced upon identification of their degraded condition. Visual examinations of the caulking, sealants, and expansion joints in the plant concluded that an inspection program was needed to adequately manage the aging of these structural components. [Reference 8, Appendix O, Section 2.4]

For the caulking, sealants, and expansion joints that do not perform a fire barrier function, a new CCNPP Caulking and Sealant Inspection Program will provide requirements and guidance for the identification, inspection frequencies, and acceptance criteria for caulking, sealants, and expansion joints used in the Intake Structure to ensure that their condition is maintained at a level that allows them to perform their intended functions. The new program will establish acceptance criteria and require a baseline inspection to determine the material condition of the caulking, sealants, and expansion joints for the Intake Structure. If unacceptable degradation exists, corrective actions will be taken. A technical basis will be developed for determining the periodicity of future inspections. [Reference 8, Attachment 8]

Group 1 - (caulking, sealants, and expansion joints subject to weathering) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to weathering of caulking, sealants, and expansion joints:

- The caulking, sealants, and expansion joints provide Intake Structure intended functions as shown in Table 3.3C-2.
- Weathering was determined to be a plausible ARDM for the caulking, sealants, and expansion joints. This ARDM, if unmanaged, could eventually result in the caulking, sealants, and expansion joints not being able to perform their intended functions under CLB conditions.
- For caulking, sealants, and expansion joints that function as fire barriers, the Penetration Fire Barrier Inspection Program performs periodic visual inspections of fire barrier penetration seals, and contains acceptance criteria that ensure corrective actions will be taken such that the fire barrier intended function will be maintained.
- For caulking, sealants, and expansion joints that do not perform a fire barrier function, a new Caulking and Sealants Inspection Program will conduct inspections to detect age-related degradation, and will contain acceptance criteria that ensure corrective actions will be taken such that the intended functions will be maintained.

Therefore, there is reasonable assurance that the effects of weathering will be adequately managed such that the caulking, sealants, and expansion joints will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 2 - (fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel/rebar) - Materials and Environment

Group 2 includes the Intake Structure fluid-retaining walls and slabs that could be subject to aggressive chemical attack on concrete and corrosion of embedded steel. The fluid-retaining walls and slabs provide structural and/or functional support to SR equipment, provide shelter/protection to SR equipment, and provide flood protection barriers (internal flooding event). [Reference 8, Appendices C and E, Section 2.2]

The embedded steel/rebar is covered and protected by concrete. At CCNPP, embedded steel is used in composite structural members and as anchorage for concrete surface attachments. Reinforcing steel (rebar) and cast-in-place anchors are all treated as embedded steel/rebar in this evaluation. [Reference 8, Appendix E, Section 2.0]

The Intake Structure concrete was constructed in accordance with a CCNPP design specification that adheres to relevant ACI codes and American Society for Testing and Materials specifications for a concrete structure of low permeability. In addition, sufficient concrete cover over embedded steel/rebar was specified in accordance with the ACI 318 code to provide corrosion protection. [Reference 8, Appendix E, Section 2.4]

The fluid-retaining walls and slabs are exposed to intake water from the Chesapeake Bay. In June and August of 1968 and 1969, the chemical characteristics of the Chesapeake Bay surface water were analyzed at locations in the vicinity of CCNPP. Some of the results obtained are as follows: [Reference 8, Appendices C and E, Section 2.5; Reference 18, Pages II-12 and II-13]

- pH: range of 7.3 to 8.4;
- sulfates: range of 770 to 1150 parts per million (ppm); and
- chlorides: range of 5800 to 7800 ppm.

It is assumed that there have been no significant changes in the above chemical characteristics since the original analysis was performed.

Group 2 - (fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel/rebar) - Aging Mechanism Effects

Aggressive chemical attack on concrete and corrosion of embedded steel/rebar was determined to be plausible for the Intake Structure fluid-retaining walls and slabs since the intake water could contain chemicals that might attack the concrete or cause corrosion of the embedded steel/rebar. [Reference 8, Appendices C and E, Section 2.5]

Aggressive Chemical Attack on Concrete

Concrete, being highly alkaline (pH > 12.5), is vulnerable to degradation by strong acids. Acid attack can increase porosity and permeability of concrete, reduce its alkaline nature at the surface of the attack, reduce strength, and render the concrete subject to further deterioration. A dense concrete with low permeability and a low water-to-cement ratio may provide an acceptable degree of protection against mild acid attack. [Reference 8, Appendix C, Section 1.0; Reference 10, Section 4.1.3.1]

Chlorides and sulfates of sodium, potassium, and magnesium may attack concrete depending upon their concentrations. Sulfate attack can produce significant expansive stresses within the concrete, leading to cracking, spalling, and strength loss. Once established, these conditions allow further exposure to aggressive chemicals. Use of adequate cement content, low water-to-cement ratio, and thorough consolidation and curing contribute to low permeability and provide effective protection against sulfate and chloride attack. Based on an industry report, minimum degradation threshold limits for concrete are 500 ppm chlorides or 1,500 ppm sulfates. [Reference 8, Appendix C, Section 1.0; Reference 10, Section 4.1.3.1]

Corrosion of Embedded Steel/Rebar

Concrete's high alkalinity (pH > 12.5) provides an environment around embedded steel/rebar that protects it from corrosion. However, when the pH is reduced by the intrusion of aggressive ions, corrosion can occur. The corrosion rate is 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 (e.g., from the intake water). The severity of corrosion is influenced by the properties and type of cement and aggregates as well as the concrete moisture content. [Reference 8, Appendix E, Section 1.0; Reference 10, Section 4.1.5.1]

Corrosion products add volume to the original metal. The presence of sufficient corrosion products on embedded steel or rebar subjects the concrete to tensile stress that eventually causes hairline cracking, rust staining, spalling, and more severe cracking. These actions will expose more embedded steel/rebar to a potentially corrosive environment and cause further deterioration in the concrete. A loss of bond between the concrete and embedded steel/rebar will eventually occur, along with a reduction in steel cross-section. These conditions can ultimately impair structural integrity. [Reference 8, Appendix E, Section 1.0; Reference 10, Section 4.1.5.1]

The degree to which concrete will provide satisfactory protection for embedded steel/rebar 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, hence, 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 the resistance to water penetration and thereby provide greater resistance to corrosion. [Reference 8, Appendix E, Section 1.0 Reference 10, Section 4.1.5.1]

These aging mechanisms, if unmanaged, could eventually result in the Intake Structure fluid-retaining walls and slabs not being able to perform their intended functions under CLB conditions. Therefore, aggressive chemical attack on concrete and corrosion of embedded steel/rebar were determined to be plausible ARDMs for which the aging effects must be managed for the Intake Structure. [Reference 8, Appendices C and E, Section 2.3]

Group 2 - (fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel/rebar) - Methods to Manage Aging

Mitigation: The Intake Structure concrete is designed to have a low permeability. In addition, sufficient concrete cover over embedded steel/rebar was specified to provide corrosion protection. These design considerations help to mitigate aggressive chemical attack on concrete and corrosion of embedded steel/rebar. However, to provide further assurance that degradation is not occurring, the discovery methods described below are deemed necessary to manage these ARDMs. [Reference 8, Appendix E, Section 2.4]

Discovery: Visual inspections of the fluid-retaining walls and slabs can be performed to provide assurance that degradation of the concrete (i.e., concrete cracking, rust staining, spalling) is not occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the fluid-retaining walls and slabs will continue to perform their intended functions during the period of extended operation.

Group 2 - (fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel/rebar) - Aging Management Program(s)

Mitigation: The design considerations discussed above help to mitigate aggressive chemical attack on concrete and corrosion of embedded steel/rebar for the Intake Structure foundation and ground floor slab. There are no programs credited with mitigating these ARDMs.

Discovery: Preventive Maintenance (PM) tasks are currently in place at CCNPP that call for the periodic draining of the Intake Structure cavities during refueling outages to scrape and wash the saltwater tunnel/cavity walls (i.e., the fluid-retaining walls and slabs). Visual inspections are performed after cleaning and repairs are made as required. These PM tasks will be modified to provide more specific guidance on inspecting for degradation (e.g., cracking, rust staining, spalling) that may be a result of ARDMs. The corrective actions taken as a result of these PM tasks ensure that the Intake Structure fluid-retaining walls and slabs remain capable of performing their intended functions under all CLB conditions. Operating experience associated with performance of these PM tasks is that no significant age-related degradation of the concrete has been identified. [Reference 19]

These PM tasks dewater the Intake Structure cavities and associated saltwater tunnels by the installation of stop logs in the vicinity of the trash racks. This allows inspection of the fluid-retaining walls and slabs downstream of the stop logs. The portion of the Intake Structure fluid-retaining walls and slabs upstream of the stop logs are not inspected by these PM tasks. However, all of the Intake Structure fluid-retaining walls and slabs are subject to the same environmental conditions. Therefore, the portions that are inspected are considered representative of all of the Intake Structure fluid-retaining walls and slabs. Any conditions adverse to quality discovered during these inspections are documents on Issue Reports in accordance with the CCNPP Corrective Actions Program. Issue Reports are required to identify the extent of the issue, including the suspected boundary of the problem. Corrective actions are taken as required as part of the Issue Report resolution process. For the Intake Structure fluid-retaining walls and slabs, this corrective action would include the use of divers to inspect the portion upstream of the stop logs if deemed necessary. [Reference 19; Reference 20, Attachment 1]

The PM tasks described above are performed in accordance with the CCNPP PM Program. This program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. [Reference 21, Section 1.1]

The program is governed by CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," and covers all PM activities for nuclear power plant structures and equipment within the plant. Guidelines drawn from industry experience and utility best practices were used in the development and enhancement of this program. [Reference 21, Section 2.1]

The PM Program includes periodic inspection of specific structures and components through various maintenance activities. These activities provide an effective means to discover and manage the age-related degradation effects on these structures and components. The program requires that an Issue Report be initiated according to CCNPP Procedure QL-2-100, "Issue Reporting and Assessment," for deficiencies noted during performance of PM tasks. The corrective actions taken ensure that the affected structures and components remain capable of performing their intended functions under all CLB conditions. [Reference 21, Section 5.2.B.1.f]

Specific responsibilities are assigned to BGE personnel for evaluating and upgrading the PM Program and for initiating program improvements based on system performance. Issue Reports are initiated according to CCNPP Procedure QL-2-100 to request changes to the program that could improve or correct plant reliability and performance. Changes to the PM Program that require Issue Reports include changes to the

PM task scope, frequency, process changes, results from operating experience reviews, as well as other types of changes. [Reference 21, Sections 5.1.A and 5.4.B]

The PM Program is subject to periodic internal assessment. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. An audit performed in 1997 of the CCNPP Maintenance Program (which includes the PM Program) concluded that the program is effectively implemented at CCNPP. No age-related degradation issues were identified. [Reference 15, Section 1B.18]

Group 2 - (fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel/rebar) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to aggressive chemical attack on concrete and corrosion of embedded steel/rebar for the Intake Structure fluid-retaining walls and slabs:

- The fluid-retaining walls and slabs provide structural and/or functional support to SR equipment, provide shelter/protection to SR equipment, and provide flood protection barriers (internal flooding event).
- Aggressive chemical attack on concrete and corrosion of embedded steel/rebar are plausible for the Intake Structure fluid-retaining walls and slabs since the intake water could contain chemicals that might attack the concrete or cause corrosion of the embedded steel/rebar. These ARDMs, if unmanaged, could eventually result in the fluid-retaining walls and slabs not being able to perform their intended functions under CLB conditions.
- The PM Program conducts periodic inspections of the Intake Structure fluid-retaining walls and slabs through performance of various PM tasks that provide the means to discover and manage age-related degradation. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected structures or components remain capable of performing their intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of aggressive chemical attack on concrete and corrosion of embedded steel/rebar will be adequately managed such that the fluid-retaining walls and slabs will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 3 - (steel components subject to corrosion) - Materials and Environment

Group 3 includes the Intake Structure steel components marked with an asterisk in Table 3.3C-2. These components are all subject to corrosion. They each contribute to one or more of the various Intake Structure intended functions as shown in Table 3.3C-2. [Reference 8, Appendix K, Section 2.2]

Since corrosion was recognized as a potential degradation mechanism for all structural steel components of the Intake Structure, its effects were considered in the original design. As a result, all exposed structural steel surfaces in the Intake Structure except galvanized steel such as grating, checkered plate, and metal decking, were shop-painted or field-painted during plant construction. [Reference 8, Appendix K, Section 2.4]

The steel components located indoors will be subject to the ambient conditions within the Intake Structure. The Intake Structure ambient temperature is controlled by a plant ventilation system as described in UFSAR Chapter 9. The steel components located outdoors will be subject to the temperature and humidity changes, rain, snow, etc. expected at the CCNPP site. [Reference 3, Section 9.8.2.6, Table 9-18]

Group 3 - (steel components subject to corrosion) - Aging Mechanism Effects

Steel corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. Initially, the exposed steel surface reacts with oxygen and moisture to form an oxide film as rust. Once the protective oxide film has been formed and if it is not disturbed by erosion, alternating wetting and drying, or other surface actions, the oxidation rate will diminish rapidly with time. Chlorides, either from saltwater, the atmosphere, or groundwater, increase the rate of corrosion by increasing the electrochemical activity. If steel is in contact with another metal that is more noble in the galvanic series, corrosion of the steel may accelerate. [Reference 8, Appendix K, Section 1.0]

Corrosion products, such as hydrated oxides of iron (rust), form on exposed, unprotected surfaces of the steel and are readily visible. The affected surface may degrade to such an extent that visible perforation may occur. In the case of exposed surfaces of steel with protective coatings, corrosion may cause the protective coatings to lose their ability to adhere to the corroding surface. In this case, damage to the coatings can be visually detected well in advance of significant degradation of the steel. [Reference 8, Appendix K, Section 1.0]

Visual inspection of accessible interior and exterior areas of the Intake Structure was performed in 1994. This inspection identified minor areas of rust on steel components. [Reference 8, Attachment 7]

This aging mechanism, if unmanaged, could eventually result in the steel components not being able to perform their intended functions under CLB conditions. Therefore, corrosion was determined to be a plausible ARDM for which the aging effects must be managed for the Intake Structure steel components. [Reference 8, Appendix K, Section 2.3]

Group 3 - (steel components subject to corrosion) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of the steel components to an aggressive environment and protecting the external surfaces with paint or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces.

Discovery: The effects of general corrosion/oxidation of steel are detectable by visual inspection. A visual examination by a person familiar with the components can be used to determine general mechanical and structural condition and check for rust. Observing that significant degradation of protective coatings has not occurred is an effective method to ensure that corrosion has not affected the intended function of the structural component. Since the coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition that triggers corrective action before the occurrence of corrosion that would affect the components' ability to perform their intended functions. The degradation of the protective coating that does occur can be discovered and monitored by periodically inspecting the steel structural components. Corrective action for failed protective coatings and any actual metal degradation can be carried out as necessary. [Reference 8, Appendix K, Section 3.0]

Group 3 - (steel components subject to corrosion) - Aging Management Programs

Mitigation: No programs are credited for mitigation. The exposed surfaces of structural steel components are covered by protective coatings that mitigate the effects of corrosion. The discovery programs discussed below verify that the protective coatings are maintained.

Discovery: Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of corrosion of steel (or conditions that would accelerate corrosion, such as pooled water) for the Intake Structure by performance of visual inspections during plant walkdowns. The purpose of the program is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. This program is applicable to the Intake Structure steel components. [Reference 22, Section 1.1]

Under this program, responsible personnel perform periodic walkdowns of their assigned structures and systems. Walkdowns may also be performed as required for reasons such as: material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when the system is initially pressurized, energized, or placed in service); and as required for plant modifications. [Reference 22, Section 5.1]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any abnormal or degraded condition will be identified, documented, and corrective actions taken before the condition proceeds to failure of the structures, systems, and components to perform their intended functions. Conditions adverse to quality are documented and resolved by the CCNPP Corrective Actions Program. [Reference 22, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The program provides guidance for identification of specific types of degradation or conditions when performing the walkdowns. Inspection items related to aging management include the following: [Reference 22, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

The program includes a walkdown checklist specifically for the Intake Structure. The checklist includes a section targeted at structural steel components. Checklist items include visual inspection for corrosion, rust stains, and flaking/bubbling of protective coatings. [Reference 22, Attachment 6]

A structure performance assessment is currently required for Category I structures at CCNPP at least once every six years. The assessment includes a review of each structural component that could degrade the overall performance of the structure. The program will be modified to add guidance regarding approval authority for significant departures from the walkdown scope/schedule specified. [Reference 22, Section 5.3]

The corrective actions taken as a result of the program described above will ensure that the Intake Structure steel components will remain capable of performing their intended functions under all CLB conditions.

Group 3 - (steel components subject to corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of steel components for the Intake Structure:

- The Intake Structure steel components contribute to one or more of the various Intake Structure intended functions as shown in Table 3.3C-2.
- The steel components are subject to corrosion due to the normal ambient environmental conditions. This ARDM, if unmanaged, could eventually result in the steel components not being able to perform their intended functions under CLB conditions.
- Corrosion is mitigated by applying protective coatings to the steel components and by periodically examining the components for degradation of that coating or conditions that could accelerate degradation.
- Calvert Cliffs procedure MN-1-319 provides for periodic visual inspections of these components during walkdowns of the Intake Structure. If any degradation is found, the appropriate corrective actions are taken to ensure that the intended functions will be maintained.

Therefore, there is reasonable assurance that the effects of aging due to corrosion of steel will be managed such that the steel components of the Intake Structure will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 4 - (sluice gates subject to corrosion) - Materials and Environment

Group 4 includes the Intake Structure sluice gates, which are subject to corrosion. These Intake Structure unique components provide structural and/or functional support to SR equipment as shown in Table 3.3C-2. The specific corrosion mechanisms that are plausible are crevice corrosion, MIC, and pitting. [Reference 8, Appendix K, Section 2.2]

The sluice gates are used to isolate the circulating water pump inlet bays from the saltwater pump suction pits for maintenance purposes. There are a total of twelve sluice gates (six for each CCNPP unit, two associated with each saltwater pump). Each sluice gate consists of a gate, a gate frame, a stem, a lift mechanism, and two wire rope/chain assemblies. The gate slides vertically in the gate frame to shut or open the tunnel to the associated saltwater pump. The stem is attached to the top of the gate and extends up to the lift mechanism. The two wire rope/chain assemblies are provided to hold the sluice gate open in case the stem or lift mechanism fails. The SR function of each gate is to remain in a fixed position above the tunnel so as to not inhibit flow to the Saltwater System. The two wire rope/chain assemblies and associated fittings are credited for this function. The wire rope is constructed of monel. The chain and fittings are constructed of Type 316 stainless steel. [Reference 23; Reference 24, Page 65]

The lower portions of the wire rope/chain assemblies are subject to a saltwater environment (i.e., intake water from the Chesapeake Bay). The concentrations of sulfates and chlorides in the intake water are described above in the Aging Mechanism Effects section for Group 2. The upper portions of the wire rope/chain assemblies are subject to the outdoor environmental conditions expected at the CCNPP site.

Group 4 - (sluice gates subject to corrosion) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, and other mechanical joints that have a crevice geometry. 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. Crevice corrosion is closely related to pitting corrosion and can initiate pits (i.e., loss of material) in many cases. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. [Reference 25, Attachment 7 for Valves]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. This form of corrosion essentially produces holes of varying depth to diameter ratios in the metal. High concentrations of impurity anions such as chlorides and sulfates tend to concentrate in the oxygen depleted pit region, giving rise to a potentially concentrated aggressive solution in this zone. [Reference 25, Attachment 7 for Valves]

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria are most commonly associated with corrosion effects. This ARDM most often results in pitting, followed by excessive deposition of corrosion products. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. Temperatures from about 50°F to 120°F are most conducive to MIC. [Reference 25, Attachment 7 for Valves]

Crevice corrosion and pitting are plausible for monel and stainless steel in a saltwater environment. The monel and stainless subcomponents of the wire rope/chain assemblies and associated fittings are susceptible to crevice corrosion and pitting due to the presence of sulfates and chlorides in the intake water. [Reference 25, Attachments 3, 4, 5, and 6 for Group IDs HV-01 and RV-01]

Microbiologically-induced corrosion is plausible for monel and stainless steel in a saltwater environment. The monel and stainless subcomponents of the wire rope/chain assemblies and associated fittings are susceptible to MIC since sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the intake water. [Reference 25, Attachments 3, 4, 5, and 6 for Group IDs HV-01 and RV-01]

The sluice gates have experienced corrosion in the past. Moderate corrosion of the sluice gates was observed in 1986, and new sluice gates were subsequently installed. [Reference 26]

This aging mechanism, if unmanaged, could eventually result in a loss of material such that the sluice gates may not be able to perform their intended function under CLB conditions. Therefore, corrosion was determined to be a plausible ARDM for which the aging effects must be managed for the sluice gates. [Reference 8, Appendix K, Section 2.3]

Group 4 - (sluice gates subject to corrosion) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but it can be mitigated by design through selection of materials appropriate for saltwater service.

Discovery: The effects of corrosion are detectable by visual inspection. A visual examination by a person familiar with the components can be used to determine general mechanical and structural condition and check for corrosion. Corrective action for any metal degradation can be carried out as necessary.

Group 4 - (sluice gates subject to corrosion) - Aging Management Programs

Mitigation: No programs are credited for mitigation of corrosion of the sluice gates.

Discovery: The sluice gates are subject to periodic inspection through existing PM activities as part of the CCNPP PM Program. The sluice gate inspections are currently performed each refueling outage with the Intake Structure cavities dewatered through the use of stop logs. The wire rope/chain assemblies and associated fitting are typically inspected as part of the sluice gate inspections. However, the PM tasks do not specifically identify the wire rope/chain assemblies and associated fittings as subcomponents of the sluice gates that require inspection. Therefore, the existing PM tasks will be modified or new PM tasks will be initiated to provide specific instructions for inspection of these subcomponents. Periodic inspection of the wire rope/chain assemblies and associated fittings verifies that no significant corrosion is occurring and corrective actions are taken as required to ensure that the sluice gates will remain capable of performing their intended function under all CLB conditions. [References 27 and 28]

The CCNPP PM Program details are discussed above in the Aging Management Program section for Group 2.

Group 4 - (sluice gates subject to corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of the sluice gates:

- The sluice gates provide structural and/or functional support to SR equipment.

- The sluice gates are subject to corrosion due to exposure to the saltwater environment. This ARDM, if unmanaged, could eventually result in the sluice gates not being able to perform their intended function under CLB conditions.
- The PM Program conducts periodic inspections of the sluice gates through performance of various PM tasks that provide the means to discover and manage corrosion. Corrective actions are taken to correct any deficiencies that are found to ensure that the sluice gates remain capable of performing their intended function under all CLB conditions.

Therefore, there is reasonable assurance that the effects of aging due to corrosion will be managed such that the sluice gates will be capable of performing their intended function, consistent with the CLB, during the period of extended operation.

3.3C.3 Conclusion

The aging management programs discussed for the Intake Structure are listed in the following table. These programs are (or will be for new programs) administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the Intake Structure will be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 3.3C-4

LIST OF AGING MANAGEMENT PROGRAMS FOR THE INTAKE STRUCTURE

	Program	Credited As
Existing	CCNPP Technical Procedure STP-F-592-1/2, "Penetration Fire Barrier Inspection"	Discovery of weathering effects for caulking, sealants, and expansion joints that function as fire barriers for the Intake Structure. (Group 1)
Modified	PM Program Repetitive Tasks 10092042, 10092043, 10092044, 10092045, 10092046, 10092047, 20092039, 20092040, 20092041, 20092042, 20092043, and 20092044 for Intake Structure Cavity Repairs and Cleaning during Refueling Outages	Discovery of aggressive chemical attack and corrosion of embedded steel/rebar effects on the exterior surfaces of concrete fluid-retaining walls and slabs for the Intake Structure. (Group 2)
Modified	CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns"	Discovery of corrosion effects for steel components in the Intake Structure. (Group 3)
Modified or New	PM Program PM tasks for Inspection of Sluice Gates	Discovery of corrosion effects for sluice gates. (Group 4)
New	Caulking and Sealant Inspection Program	Discovery of weathering effects for caulking, sealants, and expansion joints that do not function as fire barriers for the Intake Structure. (Group 1)

3.3C.4 References

1. CCNPP "Integrated Plant Assessment Methodology," Revision 1, January 11, 1996
2. CCNPP "Component Level Scoping Results for the Intake Structure," Revision 2, February 12, 1997
3. CCNPP Updated Final Safety Analysis Report, Revision 20
4. CCNPP "Life Cycle Management System and Structure Screening Results," Revision 5, September 10, 1997
5. CCNPP Drawing 61230, "Salt Water Systems Underground Ducts Plan and Sections," Revision 6, October 15, 1990
6. CCNPP Drawing 63874SH0004, "SR Ductbank Under West Plant Road Plan," Revision 0, April 4, 1995
7. CCNPP Drawing 63874SH0005, "Underground Conduit West of Turbine Building Plan," Revision 0, July 15, 1996
8. CCNPP "Aging Management Review Report for the Intake Structure," Revision 3A, February 12, 1997
9. CCNPP "Aging Management Review Report for Component Supports," Revision 3, February 4, 1997
10. Electric Power Research Institute Report TR-103842, "Class I Structures License Renewal Industry Report," Revision 1, July 1994
11. CCNPP Specification A-0010 (Bechtel Specification No. 6750-A-10), "Specification for Furnishing, Delivery and Application of the Caulking and Sealants," Revision 1, March 3, 1971
12. CCNPP Specification C-0010 (Bechtel Specification No. 6750-C-10), "Specification for Forming, Placing, Finishing, and Curing Concrete," Revision 9, January 8, 1976
13. CCNPP Technical Procedure STP-F-592-1, "Penetration Fire Barrier Inspection," Revision 3, August 26, 1997
14. CCNPP Technical Procedure STP-F-592-2, "Penetration Fire Barrier Inspection," Revision 2, August 26, 1997
15. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48, March 28, 1997
16. Letter from Mr. L. T. Doerflein (NRC) to Mr. C. H. Cruse (BGE), dated May 14, 1997, "Plant Performance Review (PPR) - Calvert Cliffs"
17. Letter from Mr. J. T. Trapp (NRC) to Mr. R. E. Denton (BGE), dated May 6, 1994, "Combined Inspection Report Nos. 50-317/94-15 and 50-318/94-15"
18. "Final Environmental Statement related to Operation of Calvert Cliffs Nuclear Power Plant Units 1 and 2," Baltimore Gas and Electric Company, Dockets Nos. 50-317 and 50-318, United States Atomic Energy Commission, Directorate of Licensing, April 1973

19. CCNPP NUCLEIS Database, Repetitive Tasks 10092042, 10092043, 10092044, 10092045, 10092046, 10092047, 20092039, 20092040, 20092041, 20092042, 20092043, and 20092044 for Intake Structure Cavity Repairs and Cleaning during Refueling Outages
20. CCNPP Administrative Procedure QL-2-100, "Issue Reporting and Assessment," Revision 8, December 8, 1997
21. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996
22. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0, September 16, 1997
23. CCNPP Drawing 61841, "Intake Structure Sluice Gates and Stop Logs," Revision 8, June 6, 1996
24. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 2, September 15, 1997
25. CCNPP "Aging Management Review Report for the Saltwater System," Revision 4, February 11, 1997
26. Letter from Mr. E. C. Wenzinger (NRC) to Mr. J. A Tiernan (BGE), dated December 19, 1986, "NRC Resident Inspection 50-317/86-18, 50-318/86-18"
27. CCNPP Technical Procedure HE-48, "Sluice Gate Inspection," Revision 1, April 23, 1996
28. CCNPP NUCLEIS Database, Repetitive Tasks 10122016, 10122010, 10122012, 10122051, 10122052, 10122015, 20122041, 20122050, 20122051, 20122052, 20122053, and 20122043 for Sluice Gate Inspections per Procedure HE-48

3.3D Miscellaneous Tank and Valve Enclosures

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the No. 12 Condensate Storage Tank (CST) Enclosure, the No. 21 Fuel Oil Storage Tank (FOST) Enclosure, and the Auxiliary Feedwater (AFW) Valve Enclosure. These enclosures were evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

3.3D.1 Structures Scoping

The systems and structures scoping task identifies structures within the scope of license renewal on the basis of how their design supports generic structural functions satisfying the 10 CFR 54.4(a) scoping criteria. The component level scoping process for structures is conducted on the basis of a generic listing of structural component types. Scoping is implemented by determining which structural component types are required for performance of the passive intended functions of the structure.

By their nature, structures within the scope of license renewal are constructed in accordance with predetermined design requirements to support performance of specific structural functions. Civil engineers experienced with nuclear plant structures established the following generic list of structural functions for CCNPP. A structure is considered to be within the scope of license renewal if it performs one or more of these structural functions: [Reference 1, Section 4.2.2]

- Provide structural and/or functional support to safety-related (SR) equipment;
- Provide shelter/protection to SR equipment;
- NOTE: This function includes: (a) protection from radiation effects for equipment addressed by the Environmental Qualification Program; and (b) protection from High Energy Line Break effects.
- Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated Design Basis Events;
- Serve as a missile barrier (internal or external);
- Provide structural and/or functional support to non-safety-related (NSR) equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions (e.g., seismic Category II over I design considerations);
- Provide flood protection barrier (internal flooding event); and
- Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant.

This section begins with a description of the miscellaneous tank and valve enclosures. The intended functions performed by each enclosure are listed and used to identify the structural component types within the scope of license renewal (i.e., those required to perform the intended functions). Finally, the components subject to Aging Management Review (AMR) are identified and dispositioned in accordance with the CCNPP IPA Methodology.

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

Structure Description/Conceptual Boundaries

Figure 3.3D-1 is a simplified layout showing the site structures that are within the scope of license renewal, including the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures. [References 2 through 5] A comprehensive layout and description of all site structures is provided in the Updated Final Safety Analysis Report, Chapter 1, with further discussion of their design features in Chapter 5 and Appendix 5A. [Reference 6, Chapters 1, 5, and Appendix 5A] A general description, boundary, and design discussion for the enclosures addressed in this section follows:

- **No. 12 CST Enclosure** is located in the tank farm area north of the Turbine Building and is common for both Units 1 and 2. It houses and protects No. 12 CST, which provides demineralized water for decay heat removal and cooldown of Units 1 and 2. [Reference 7, Section 1.1.1; Reference 8, Section 1.1.1] (The No. 12 CST is within the scope of license renewal for the AFW System, which is evaluated in Section 5.1 of the BGE LRA.) The structural boundary comprises all of the enclosure's structural components such as walls, foundation slab, and roof slab. [Reference 8, Section 1.1.2] The No. 12 CST Enclosure is required to meet Seismic Category I criteria because it houses SR systems, equipment, or components that must remain functional before, during, or after a safe shutdown earthquake. [Reference 9, pages 46, 57, and 58] Additionally, the structural boundary includes structural or functional supports for NSR roof drains and tank vents. During an abnormal event such as a seismic event, failure of these NSR equipment supports must not adversely affect the operability of SR components. The enclosure is a reinforced concrete structure of sufficient thickness to stop tornado-generated missiles and to resist tornado wind pressures. Bursting pressures are relieved by baffled, missile-proof vents. [Reference 6, Section 10.3.2]

- **No. 21 FOST Enclosure** is located in the yard area west of the Unit 2 Containment Structure and is common for both Units 1 and 2. It houses and protects No. 21 FOST, which provides a fuel supply for the three emergency diesel generators installed in the Auxiliary Building. [Reference 6, Sections 1.2.2 and 8.4.1.2; Reference 10, Section 1.1.1] (The No. 21 FOST is within the scope of license renewal for the Diesel Fuel Oil System, which is evaluated in Section 5.7 of the BGE LRA.) The structural boundary comprises all of the enclosure's structural components such as concrete foundations, walls, and slabs. Additionally, the structural boundary includes structural or functional supports for NSR stairs and platforms. During an abnormal event such as a seismic event, failure of these NSR equipment supports must not adversely affect the operability of SR components. [Reference 10, Section 1.1.2] The No. 21 FOST Enclosure is required to meet Seismic Category I criteria because it houses SR systems, equipment, or components that must remain functional before, during, or after a safe shutdown earthquake. [Reference 9, pages 46, 57, and 58] The enclosure is a reinforced concrete structure designed to protect No. 21 FOST from tornadoes and tornado missiles. Bursting pressures are relieved by baffled, missile-proof vents. The structure will also withstand the impact of a transmission tower falling on it without damage to the No. 21 FOST. The enclosure also acts as a dike in the event of a tank failure. [Reference 6, Section 8.4.1.2]

APPENDIX A - TECHNICAL INFORMATION
3.3D - MISCELLANEOUS TANK AND VALVE ENCLOSURES

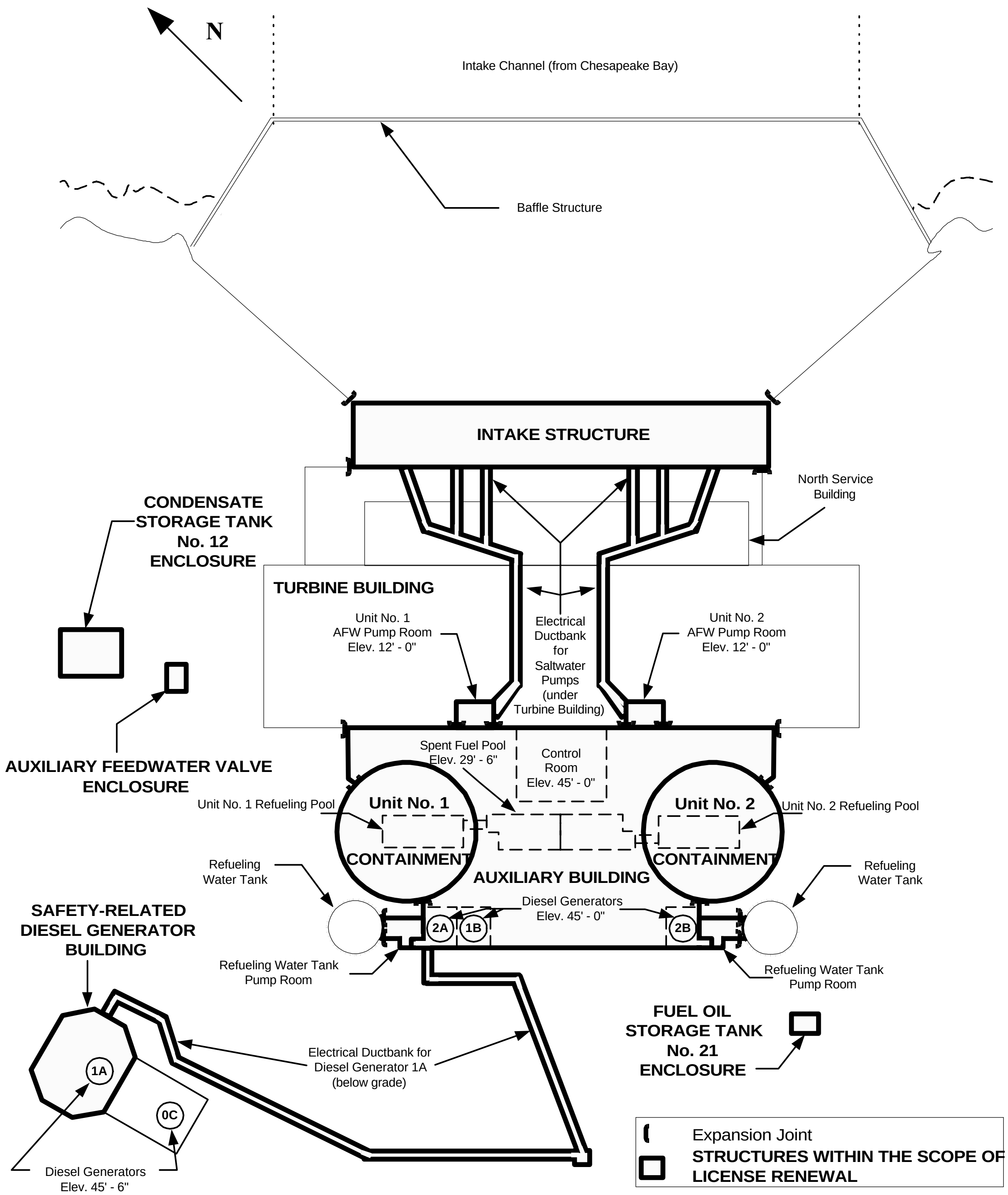

FIGURE 3.3D-1
CCNPP SITE STRUCTURES
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

- **AFW Valve Enclosure** is located in the tank farm area north of the Turbine Building and is common for both Units 1 and 2. It houses and protects the AFW pump suction valves and associated manifold piping, which provide a pressure boundary function for the AFW System. [Reference 11, Table 2; Reference 12] (The components inside this enclosure are within the scope of license renewal for the AFW System, which is evaluated in Section 5.1 of the BGE LRA.) The structural boundary comprises all of the enclosure's structural components such as concrete foundations, walls, and slabs. Additionally, the structural boundary includes structural or functional supports for NSR manhole steps and grating. During an abnormal event such as a seismic event, failure of these NSR equipment supports must not adversely affect the operability of SR components. The AFW Valve Enclosure is required to meet Seismic Category I criteria because it houses SR systems, equipment, or components that must remain functional before, during, or after a safe shutdown earthquake. The enclosure is a reinforced concrete structure designed to withstand and protect its associated piping from design basis loadings (e.g., weight, thermal, seismic, and wind). [References 9 and 13]

Component supports that are connected to structural components in the miscellaneous tank and valve enclosures are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. A "component support" is the connection between a system, or component within a system, and a plant structural member. Component supports interface with the components they support in the applicable systems, and they interface with the structural component to which they are attached. For example, a fixed base supporting a pump is considered a component support since it connects the concrete equipment pad to the pump. The pump itself would be scoped within its associated system evaluation. The fixed base would be scoped within the Component Supports Commodity Evaluation, and the concrete equipment pad would be scoped within the evaluation for the associated structure. If anchor bolts are used at the interface with the structural member, there is overlap between the Component Supports Commodity Evaluation and the evaluation for the structural component. Evaluations for structural components considered the effects of aging caused by the surrounding environment, while the Component Supports Commodity Evaluation considered the effects of aging caused by the supported equipment (thermal expansion, rotating equipment, etc.) as well as the surrounding environment. Supports for structural components (e.g., platform hangers) are not "component supports" in this sense because any support for a structural component is itself a structural component (i.e., included in the scope of the associated structure). [Reference 14, Section 1.1.1]

Scoped Structures and Their Intended Functions

The No. 12 CST, No. 21 FOST, and AFW Valve Enclosures are in scope for license renewal based on 10 CFR 54.4(a). Four of the seven generic structural functions listed above are applicable to the miscellaneous tank and valve enclosures as shown in Table 3.3D-1. The intended functions for these enclosures were determined based on the requirements of §54.4(a)(1), §54.4(a)(2), and §54.4(a)(3) in accordance with the CCNPP IPA Methodology Section 4.2.2. [Reference 1; Reference 2, Table 2; Reference 8, Section 1.1.3; Reference 10, Section 1.1.3]

TABLE 3.3D -1
INTENDED FUNCTIONS FOR MISCELLANEOUS TANK AND VALVE ENCLOSURES

Function	Applicable to Miscellaneous Tank and Valve Enclosures?	Applicable 10 CFR 54.4(a) Criteria
1. Provide structural and/or functional support to SR equipment	Yes	§54.4(a)(1)
2. Provide shelter/protection to SR equipment NOTE: These structures are not required to provide protection from radiation or High Energy Line Break effects.	Yes	§54.4(a)(1)
3. Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated Design Basis Events	No	§54.4(a)(1)
4. Serve as a missile barrier (internal or external)	Yes	§54.4(a)(1)
5. Provide structural and/or functional support to NSR equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions (e.g., seismic Category II over I design considerations)	Yes	§54.4(a)(2)
6. Provide flood protection barrier (internal flooding event)	No	§54.4(a)(2)
7. Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant	No	§54.4(a)(3)

Components Subject to AMR

A generic list of structural component types was developed for use during the structural component scoping task. The generic list started with structural component types associated with SR functions contained in industry technical reports addressing Containment and Category I Structures. Other structural component types related to fire and flooding events were added to the list to ensure completeness. [Reference 1, Section 4.2.3] These structural components were combined into the following four structural categories based on their design and materials: [References 15 and 16]

- Concrete components;
- Structural steel components;
- Architectural components; and
- Unique components.

During the scoping process, applicable structural component types actually contained in the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures were identified. Within the four structural component categories, 17 structural component types were determined to contribute to at least one of the structural intended functions listed in Table 3.3D-1 for the associated enclosure. Table 3.3D-2 lists the structural component types and the associated functions that apply to the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures. Unless otherwise noted, structural components that are part of the structure, but do not contribute to any of the intended functions of the structure, are not listed in Table 3.3D-2. [References 15, 16, and 17]

Per the license renewal rule, ". . . Structures and components subject to an aging management review shall encompass those structures and components (i) That perform an intended function, as described in §54.4 without moving parts or without a change in configuration or properties . . . and (ii) That are not subject to periodic replacement based on a qualified life or specified time period . . . " From reviewing the generic list of structural functions, it is clear that none of the intended structural functions requires moving parts or a change in configuration or properties. Plant structural components are not normally subject to periodic replacement programs; therefore, they are considered to be long-lived unless specific justification is provided to the contrary. [Reference 1, Section 5.4]

Based on the results of the process described above, the 17 structural component types, listed in Table 3.3D-2, are subject to AMR and are evaluated within this section. [References 8 and 10, Table 2-1; Reference 17]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

TABLE 3.3D -2

STRUCTURAL COMPONENT TYPES REQUIRING AMR FOR MISCELLANEOUS TANK AND VALVE ENCLOSURES

	No. 21 FOST Enclosure	No. 12 CST Enclosure	AFW Valve Enclosure
Concrete (Including Reinforcing Steel)			
Foundations (Footings, beams, and mats)	1, 2	1, 2	1, 2
Walls	2, 4, 5	1, 2, 4, 5	1, 2, 4
Roof Slabs	2, 4, 5	2, 4, 5	2, 4
Cast-In-Place Anchors/Embedments*	1, 2, 4, 5	1, 2, 4	1, 2, 4
Grout	1, 2, 4, 5	2	NA
Post-Installed Anchors*	5	1, 5	NA
Structural Steel			
Beams*	2, 4, 5	2, 4, 5	NA
Baseplates*	2, 4, 5	2, 4, 5	NA
Roof Framing*	2, 4, 5	2, 4, 5	NA
Bracing*	5	NA	NA
Platform Hangers*	5	none	NA
Decking*	2, 4, 5	2, 4, 5	2, 4
Floor Grating*	5	none	5
Stairs and Ladders*	5	none	5
Architectural Components			
Unique Components			
Anchor Brackets*	1	NA	NA
Manhole Framing*	NA	NA	2, 4
Manhole Cover*	NA	NA	2, 4

* - Indicates the component type is included under the heading "Steel Components" in the discussion addressing the results of AMR in Table 3.3D-3

(#) - Indicates the component type provides the following intended function for the corresponding structure:
- 1 - Provide structural and/or functional support to SR equipment;
- 2 - Provide shelter/protection to SR equipment;
- 4 - Serve as a missile barrier (internal or external); and
- 5 - Provide structural and/or functional support to NSR equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions.

none - Indicates the component type does not contribute to the intended functions of the structure

NA - Indicates the component type is not part of the corresponding structure

3.3D.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for miscellaneous tank and valve enclosure components is given in Table 3.3D-3, with plausible ARDMs identified by a check mark (✓) in the appropriate column. [References 8 and 10, Attachments 1 and 2] For efficiency in presenting the results of these evaluations in this report, ARDM/component type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components. Table 3.3D-3 also identifies the group to which each ARDM/component type combination belongs. One group has been selected for the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures:

Group 1: corrosion of steel (for components marked with an asterisk in Table 3.3D-2).

TABLE 3.3D-3
POTENTIAL AND PLAUSIBLE ARDMs
FOR MISCELLANEOUS TANK AND VALVE ENCLOSURES

Potential ARDMs	Foundations	Walls	Roof Slabs	Grout	Steel Components*
Freeze-Thaw					
Leaching of Calcium Hydroxide					
Settlement					
Corrosion of Steel					✓(1)

* - "Steel Components" represents all items marked with an asterisk (*) in Table 3.3D-2
✓ - Indicates plausible ARDM determination
(#) - Indicates the group(s) in which the ARDM/component type combination is evaluated

Aging mechanisms that are not plausible are generally not discussed further in these BGE LRA sections, unless they are considered noteworthy. For the Miscellaneous Tank and Valve Enclosures, settlement is considered noteworthy and is discussed below.

Industry technical reports conclude that settlement is a potentially significant ARDM for pressurized water reactor Containment Structures and for other Category I Structures at some plants. [Reference 18, Section 5.5; Reference 19, Section 5.1.2] Settlement occurs both during construction and after construction. The amount of settlement depends on the physical properties of the foundation material. [References 8 and 10, Appendix Js] Excavation unloading and structural loading during construction caused a small change in the void ratio of undisturbed soil. This change results in a very small or negligible amount of time-dependent settlement. [Reference 6, Section 2.7.6.2; References 8 and 10, Appendix Js] Compacted soil is subject to some degree of settlement in the first several months after construction. [Reference 19, Section 4.6.3.1] Settlement directly related to construction work is readily evident early in the life of the structure and is not considered to be an ARDM. Settlement may occur during the design life of the structure from changes in environmental conditions, such as lowering of the groundwater table. Sites with soft soil and/or sites with significant changes in underground water conditions over a long period of time may be susceptible to significant settlement. [References 8 and 10, Appendix Js; Reference 18, Section 4.5.3.2; Reference 19, Section 4.6.3.2] Concrete and steel structural members can be affected by differential settlement between supporting foundations, within a building, or between buildings. Severe settlement can cause misalignment of equipment and lead to overstress conditions within the structure. When buildings experience significant settlement, cracks in structural members, differential elevations of supporting members bridging between buildings, or both may be visibly detected. [References 8 and 10, Appendix Js] At CCNPP, long-term settlement was determined to be not plausible for the miscellaneous tank and valve enclosures based on the following site-specific justification:

- The foundations for the miscellaneous tank and valve enclosures are situated on an engineered soil structure consisting of compacted soil on top of the site's Pliestocene deposit. [Reference 6, Section 2.7.3; References 8 and 10, Appendix Js; Reference 20] Quality assurance and quality control measures imposed during backfill placement included specification of maximum lift thicknesses and verification of a minimum fill compaction of 97% based on the standard Proctor compaction method. [Reference 6, Section 2.7.6.1; References 20 and 21] A continuous program of soil testing during construction assured uniform placement of the compacted fill. [Reference 22] These activities assured that the causes of excessive settlement of plant structures at other nuclear power plant sites did not exist during construction at CCNPP. [Reference 23] Control of the placement and compaction for these engineered soil structures was used to obtain the engineering properties required to satisfy foundation design requirements.

- The foundations for the miscellaneous tank and valve enclosures are above the groundwater table. [References 13, 24, and 25] The elevation of the groundwater table beneath these structures changes with the surface topography and can be expected to fluctuate slightly as a result of climatic changes. [Reference 6, Section 2.5.3.3] Significant deviations from the seasonal cycles and occasional meteorological effects (e.g., drought conditions) observed over the past 25 years are not expected during the period of extended operation.

- The foundations for the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures tend to uniformly settle as rigid bodies. Most of the predicted settlement is expected in terms of uniform settlement, which has no adverse effect on structural components of the miscellaneous tank and valve enclosures. [References 8 and 10, Appendix Js] The effects of one-time building settlement are included in the stresses allowed by design codes and standards for piping systems. Any differential settlement is expected to be small and have negligible effect.

At CCNPP, no cracking or other evidence of settlement that would affect structural integrity has been observed to date. Walkdown inspections of the miscellaneous tank and valve enclosures, performed in 1994, found no indication of structural damage due to settlement. [References 8 and 10, Attachment 7s] An opportunity to inspect the below-grade concrete of the No. 21 FOST Enclosure in 1996 also revealed no indications of concrete cracking. These observations support the conclusion that settlement of the miscellaneous tank and valve enclosures at CCNPP is not plausible.

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

Group 1 - (corrosion of steel) - Materials and Environment

Group 1 comprises those components marked with an asterisk in Table 3.3D-2. These components are all fabricated from carbon steel, which is subject to general corrosion when exposed to moisture and oxygen. They each contribute to one or more of the various passive intended functions for the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures. For the purposes of this aging evaluation, the internal environmental conditions for these enclosures, which are not "weather-tight" facilities, are considered to be the same as the external environment. [References 8 and 10, Appendix Ks] The CCNPP site is located in a geographic region subject to severe weather conditions. All outdoor components will experience the extreme temperature ranges, rain, snow, and changes in humidity expected at the CCNPP site. Since the air inside these enclosures is not conditioned, the interior components will experience similar temperature and humidity changes throughout the life of the plant. [References 8 and 10, Appendix Os]

Since corrosion was recognized as a potential degradation mechanism for all carbon steel components of site structures, protective coatings were incorporated into the original design. Exposed structural steel surfaces in the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures were coated during the construction phase (e.g., shop-primed, field-painted, hot-dipped galvanized). [References 8 and 10, Appendix Ks; References 26 through 29]

Group 1 - (corrosion of steel) - Aging Mechanism Effects

Steel corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. Initially, the exposed steel surface reacts with oxygen and moisture to form an oxide film as rust. Once the protective oxide film has been formed, and if it is not disturbed by erosion, alternating wetting and drying, or other surface actions, the oxidation rate will diminish rapidly with time. Chlorides, either from saltwater, the atmosphere, or groundwater, increase the rate of corrosion by increasing the electrochemical activity. If steel is in contact, through an electrolytic solution, with another metal that is more noble in the galvanic series, corrosion of the steel may accelerate. [References 8 and 10, Appendix Ks]

Corrosion products such as hydrated oxides of iron (rust) form on exposed, unprotected surfaces of the steel and are readily visible. The affected surface may degrade to such an extent that visible perforation may occur. In the case of exposed surfaces of steel with protective coatings, corrosion may cause the protective coatings to lose their ability to adhere to the corroding surface. In this case, damage to the coatings can be visually detected well in advance of significant degradation of the steel. [References 8 and 10, Appendix Ks]

Visual inspection of accessible interior and exterior areas of the No. 12 CST and No. 21 FOST Enclosures were performed in 1994. [References 8 and 10, Attachment 7s] The inspections identified minor surface corrosion on steel beams of insufficient magnitude and severity to be considered a structural integrity issue. No corrosion was observed to be causing damage to protective coatings (e.g., sprayed-on fire-proofing material for roof beams in the tank room in the No. 21 FOST Enclosure; galvanized decking material; painted carbon steel structural components).

If corrosion is left unmanaged for an extended period of time, the loss of carbon steel material can result in a reduction in the load-bearing capability of the corroded parts and increased likelihood of mechanical failure. This could lead to the inability of components identified in Table 3.3D-2 to perform their intended functions under CLB design loading conditions. [References 8 and 10, Appendix Ks]

Group 1 - (corrosion of steel) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment and protecting the external surfaces with paint or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces.

Discovery: The effects of general corrosion/oxidation of carbon steel are detectable by visual inspection. A visual examination by a person familiar with the components can be used to determine general mechanical and structural condition and check for rust. Observing that significant degradation of protective coatings has not occurred is an effective method to ensure that corrosion has not affected the intended function of the structural component. Since the coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition that triggers corrective action before the occurrence of corrosion that would affect the components' ability to perform their intended functions. The degradation of the protective coating that does occur can be discovered and monitored by periodically inspecting the carbon steel structural components. Corrective action for failed protective coatings and any actual metal degradation can be carried out as necessary. [References 8 and 10]

Group 1 - (corrosion of steel) - Aging Management Programs

Mitigation: The exposed metal surfaces of carbon steel structural components are covered by protective coatings that mitigate the effects of corrosion. The discovery programs discussed below verify that the protective coatings of carbon steel structural components are maintained.

Discovery: Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of corrosion of steel (or conditions that would accelerate corrosion, such as pooled water) for the structural components in the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures by performance of visual inspections during plant walkdowns. [References 8 and 10, Attachment 4s] The purpose of the program is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. [Reference 30, Section 1.1]

Under this program, responsible personnel perform periodic walkdowns of their assigned structures and systems. Walkdowns may also be performed as required for reasons such as: material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when the system is initially pressurized, energized, or placed in service); and as required for plant modifications. [Reference 30, Section 5.1]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any abnormal or degraded condition will be identified, documented, and corrective actions taken before the condition proceeds to failure of the structures, systems, and components to perform their intended functions. Conditions adverse to quality are documented and resolved by the CCNPP Corrective Actions Program. [Reference 30, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The program provides guidance for identification of specific types of degradation or conditions when performing the walkdowns. Inspection items related to aging management include the following: [Reference 30, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

The Structure and System Walkdown Program enhances the familiarity of responsible personnel with their assigned systems and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance personnel alone. The program has been improved recently through incorporation of significant additional guidance on specific activities to be included in the scope of structures walkdowns. A structure performance assessment is currently required for Category I structures at CCNPP at least once every six years. The assessment includes a review of each structural component that could degrade the overall performance of the structure (including the Group 1 carbon steel components for the miscellaneous tank and valve enclosures). [Reference 30, Section 5.3 and Attachment 4]

The program described above will be modified to: (a) specifically identify the structures within the scope of the performance assessments (including the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures); and (b) add guidance regarding approval authority for significant departures from the walkdown scope/schedule specified. The modified program will ensure that degraded conditions due to corrosion of steel are identified and corrected such that carbon steel components of the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures will be capable of performing their intended functions consistent with CLB design conditions.

Group 1 - (corrosion of steel) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of steel in the structural components of the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures.

- The carbon steel components identified in Table 3.3D-2 provide various passive intended functions for the associated enclosures, and failure could directly prevent satisfactory accomplishment of functions that must be maintained under CLB design loading conditions.
- Components in this group are exposed to moisture and oxygen in their installed locations.
- Carbon steel corrodes in the presence of moisture and oxygen, which leads to a loss of material. This could eventually result in inability of the affected components to perform their intended function(s).

- Coatings, specified during original construction, mitigate the effects of corrosion by providing a protective layer that prevents moisture and oxygen from contacting the steel.
- The CCNPP Structure and System Walkdowns program provides for periodic walkdowns of Group 1 components. The program will be modified to specify more clearly the scope and control of periodic performance assessments. The program will provide for the discovery of corrosion of steel (or conditions that would accelerate corrosion) for the components in Group 1, and ensure appropriate actions are taken in a timely manner to correct degraded components or protective coatings.

Therefore, there is reasonable assurance that the effects of aging due to corrosion of carbon steel will be managed in such a way that structural components of the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures will be capable of performing their intended functions consistent with the CLB during the period of extended operation.

3.3D.3 Conclusion

The aging management programs discussed for the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures are listed in the Table 3.3D-4. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects in such a way that the intended functions of the components of the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 3.3D -4

AGING MANAGEMENT PROGRAMS FOR MISCELLANEOUS TANK AND VALVE ENCLOSURES

	Program	Credited As
Modified	Structure and System Walkdowns (MN-1-319) • Specify scope and control of periodic structure performance assessments	Program for discovery and management of corrosion effects for carbon steel components in the No. 12 CST, No. 21 FOST, and AFW Valve Enclosures. (Group 1)

3.3D.4 References

1. CCNPP IPA Methodology, Revision 1
2. CCNPP System and Structure Screening Results, Revision 5
3. BGE Drawing 61230, "Salt Water Systems Underground Ducts Plan and Sections," Revision 6
4. BGE Drawing 63874SH0004, "SR Ductbank Under West Plant Road Plan," Revision 0
5. BGE Drawing 63874SH0005, "Underground Conduit West of Turbine Building Plan," Revision 0
6. CCNPP Updated Final Safety Analysis Report, Units 1 and 2, Revision 21
7. CCNPP Aging Management Review Report, "Auxiliary Feedwater System (036)," Revision 1
8. CCNPP Aging Management Review Report, "Condensate Storage Tank No. 12 Enclosure," Revision 2
9. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 2
10. CCNPP Aging Management Review Report, "Fuel Oil Storage Tank No. 21 Enclosure," Revision 2
11. CCNPP Component Level Scoping Results for System 036 - Auxiliary Feedwater System, Revision 2
12. BGE Drawing 60717SH0001, "Well Water, Pretreated Water, Demineralized Water and Condensate Storage System," Revision 71
13. BGE Drawing 60481, "Well Water, Pretreated Water & Condensate Storage Tank Piping, Partial Plans and Sections," Revision 20
14. CCNPP Aging Management Review Report, "Component Supports," Revision 3
15. CCNPP Component Level Scoping Results for Enclosure for Condensate Storage Tank #12, Revision 1
16. CCNPP Component Level Scoping Results for Enclosure for Fuel Oil Storage Tank #21, Revision 1
17. BGE Drawing 63798, "Yard Condensate Valve Pit Plans and Sections," Revision 1
18. Electric Power Research Institute, "PWR Containment Structures License Renewal Industry Report; Revision 1," July 1994
19. Electric Power Research Institute, "Class I Structures License Renewal Industry Report; Revision 1," July 1994
20. BGE Drawing 60119, "Compacted Fill Areas," Revision 0
21. Bechtel Specification No. 6750-C-4A, "Specification for Placement and Control of Compacted Fill - CCNPP Units 1 and 2," Revision 3
22. Bechtel Specification No. 6750-C-11-B, "Specification for Testing of Concrete, Reinforcement and Soil - CCNPP Units 1 and 2," Revision 1

23. NRC Inspection and Enforcement Circular 81-08, “Foundation Materials,” May 29, 1981
24. BGE Drawing 63755SH0001, “Yard Tank Enclosures,” Revision 1
25. BGE Drawing 63756SH0003, “Yard Tank Enclosures,” Revision 2
26. BGE Drawing 63754SH0001, “Yard Tank Enclosures,” Revision 1
27. Bechtel Specification No. 6750-C-61(Q), “Technical Specification for Furnishing and Delivering Structural Steel - CCNPP Units 1 and 2,” Revision 0
28. BGE Technical Requirements Document TRD-A-1000, “Coating Application Performance Standard,” Revision 14
29. Bechtel Specification No. 6750-A-24, “Specification for Painting and Special Coatings - CCNPP Units 1 and 2,” Revision 12
30. CCNPP Administrative Procedure MN-1-319, “Structure and System Walkdowns,” Revision 0

3.3E Auxiliary Building and Safety-Related Diesel Generator Building Structures

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Auxiliary Building, the adjacent Emergency Diesel Generator (EDG) Rooms, the Refueling Water Tank (RWT) Pump Rooms, the Safety-Related (SR) Diesel Generator Building, and the ductbank for EDG 1A. These structures, herein referred to as the Auxiliary Building and SR Diesel Generator Building Structures, were evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

3.3E.1 Structures Scoping

The systems and structures scoping task identifies structures within the scope of license renewal on the basis of how their design supports generic structural functions satisfying the 10 CFR 54.4(a) scoping criteria. The component level scoping process for structures is conducted on the basis of a generic listing of structural component types. Scoping is implemented by determining which structural component types are required for performance of the passive intended functions of the structure.

By their nature, structures within the scope of license renewal are constructed in accordance with predetermined design requirements to support performance of specific structural functions. Civil engineers experienced with nuclear plant structures established the following generic list of structural functions for CCNPP. A structure is considered to be within the scope of license renewal if it performs one or more of these structural functions: [Reference 1, Section 4.2.2]

- Provide structural and/or functional support to SR equipment;
- Provide shelter/protection to SR equipment;

  NOTE: This function includes: (a) protection from radiation effects for equipment addressed by the Environmental Qualification Program; and (b) protection from high energy line break effects.
- Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated Design Basis Events (DBEs);
- Serve as a missile barrier (internal or external);
- Provide structural and/or functional support to non-safety-related (NSR) equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions (e.g., Seismic Category II over I design considerations);
- Provide flood protection barrier (internal flooding event); and
- Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant.

This section begins with a description of the Auxiliary Building and SR Diesel Generator Building Structures. The intended functions performed by each structure are listed and used to identify the structural component types within the scope of license renewal (i.e., those required to perform the intended functions). Finally, the components subject to Aging Management Review (AMR) are identified and dispositioned in accordance with the CCNPP IPA Methodology.

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

Structure Description/Conceptual Boundaries

Figure 3.3E-1 is a simplified layout showing the site structures that are within the scope of license renewal, including the Auxiliary Building and SR Diesel Generator Building Structures. [References 2 through 5] A comprehensive layout and description of all site structures is provided in the Updated Final Safety Analysis Report (UFSAR), Chapter 1, with further discussion of their design features in Chapter 5 and Appendix 5A. [Reference 6, Chapters 1, 5, and Appendix 5A]. A general description, boundary, and design discussion for the structures addressed in this section follows:

- The **Auxiliary Building** is located between the Unit 1 and Unit 2 Containment structures, on the west side of and adjacent to the Turbine Building. The Auxiliary Building is common to CCNPP Units 1 and 2. [Reference 7, Section 1.1.1] Major structural features related to the Nuclear Steam Supply System and located inside the Auxiliary Building include the Control Room, nuclear waste treatment facilities, and facilities for new and spent fuel handling, storage, and shipment (including the spent fuel pool [SFP], the SFP storage racks, and the new fuel racks). [Reference 6, Sections 1.2.2 and 5.6.1.1] Three EDG Rooms and each Unit's RWT Pump Room are adjacent to the Auxiliary Building structure, and are supported on reinforced concrete foundations that are separate from the Auxiliary Building foundation mat. [References 8 and 9] (The components inside the Auxiliary Building and adjacent rooms that are within the scope of license renewal are evaluated by system in Section 5 of the BGE LRA.) The Auxiliary Building and adjacent rooms, and their structural components, provide support and shelter to SR and NSR equipment. All structural components enclosed within these structures that serve such functions are within the scope of license renewal. Those areas inside the Auxiliary Building that are specifically excluded from Seismic Category I requirements in the CCNPP Quality List (e.g., maintenance shops, stairways, kitchen, toilets, offices) are not within the scope of license renewal. [Reference 10, pages 58-59] The conceptual boundary of the Auxiliary Building includes the areas that house SR systems, equipment, or components that must remain functional before, during, or after a safe shutdown earthquake. Additionally, the conceptual boundary of the Auxiliary Building includes structural or functional supports for NSR components whose failure during an abnormal (e.g., seismic) event could adversely affect the operability of SR components; the associated structural components in the Auxiliary Building provide support for SR mounting of such components. [Reference 10, pages 46 and 57 through 59] The Auxiliary Building and adjacent rooms are primarily reinforced concrete structures, and their foundations support structural steel and reinforced concrete frames that consist mainly of reinforced concrete walls and floors. [Reference 6, Section 5.6.1.1] Structural components located within the conceptual boundary of the Auxiliary Building have been designed for the loads and conditions shown in Table 5-6 of the UFSAR. [Reference 6, Section 5.6.1.2] As part of modifications completed in 1992 to upgrade the spent fuel cask handling crane to meet the single-failure-proof criteria of NUREG-0554, "Single Failure Proof Cranes for Nuclear Power Plants," the capability of the associated structural components in the Auxiliary Building to withstand the postulated seismic loading was re-evaluated and found adequate. [Reference 11] Evaluations of the floor of the SFP indicate that its structural integrity will not be impaired in the unlikely event of a cask drop. [Reference 6, Sections 5.6.1.4 and 5.6.1.5]

- The **SR Diesel Generator Building** is located northwest of the Auxiliary Building and is common to CCNPP Units 1 and 2. [Reference 12, Appendix B4, Section 1.1] It houses EDG 1A, which is one of four EDGs designed to provide a dependable onsite power source capable of automatically starting and supplying the essential loads necessary to safely shut down the plant and maintain it in a safe shutdown condition under all conditions. (The other three EDGs are housed in the rooms adjacent to the Auxiliary Building described above.) [Reference 6, Sections 1.2.2 and 8.4] The SR Diesel Generator Building also houses the fuel oil storage tank for EDG 1A and other auxiliary equipment. [Reference 6, Sections 1.2.2 and 8.4.2; Reference 12, Appendix B4, Section 1.2] (The components inside this structure that are within the scope of license renewal are evaluated as part of the EDG System in Section 5.8 of the BGE LRA.) Since the SR Diesel Generator Building houses SR systems, equipment, or components that must remain functional before, during, or after a safe shutdown earthquake, it is required to meet Seismic Category I criteria, and has been designed for associated loads and conditions. [Reference 6, Section 5.6.5.2; Reference 10, pages 46, 57, and 58] The SR Diesel Generator Building is primarily a reinforced concrete structure supported on a mat foundation at grade level (i.e., Elevation 45'-0") with a partial basement in the area of the EDG pedestal. In addition, a one-story structure is provided on the east side of the building as missile protection for the main building entry and EDG area exhaust louver. [Reference 6, Section 5.6.5] The conceptual boundary of the SR Diesel Generator Building includes all structural components such as concrete foundations, walls, and slabs, as well as a buried ductbank that runs between the SR Diesel Generator Building and the Auxiliary Building for the electrical distribution for EDG 1A. Portions of this buried ductbank are also common to the Station Blackout Diesel. [Reference 6, Section 5A.2.1.2; Reference 12, Appendix B4, Section 4.2.4]

  A one-time procedure was used to evaluate aging management for structural component types within the conceptual boundary of the SR Diesel Generator Building. The evaluation produced a listing of structural component types subject to AMR grouped by materials and environment and related them to similar groupings of structural component types in the Auxiliary Building. [Reference 12, Appendix B1, Section 6.3.H] Since completion of construction in 1996, evidence of age-related degradation of the SR Diesel Generator Building has not been observed. [Reference 6, Appendix 1C, Section 1C.1] Due to similarity in function and structure to the Auxiliary Building, operating experience related to aging mechanisms and their management for the Auxiliary Building is expected to provide early warning to BGE for any aging of the SR Diesel Generator Building that will need to be managed. [Reference 12, Appendix B4, Section 1.1]

ATTACHMENT (1)

APPENDIX A - TECHNICAL INFORMATION
3.3E - AUXILIARY BUILDING AND SAFETY-RELATED DIESEL GENERATOR BUILDING STRUCTURES

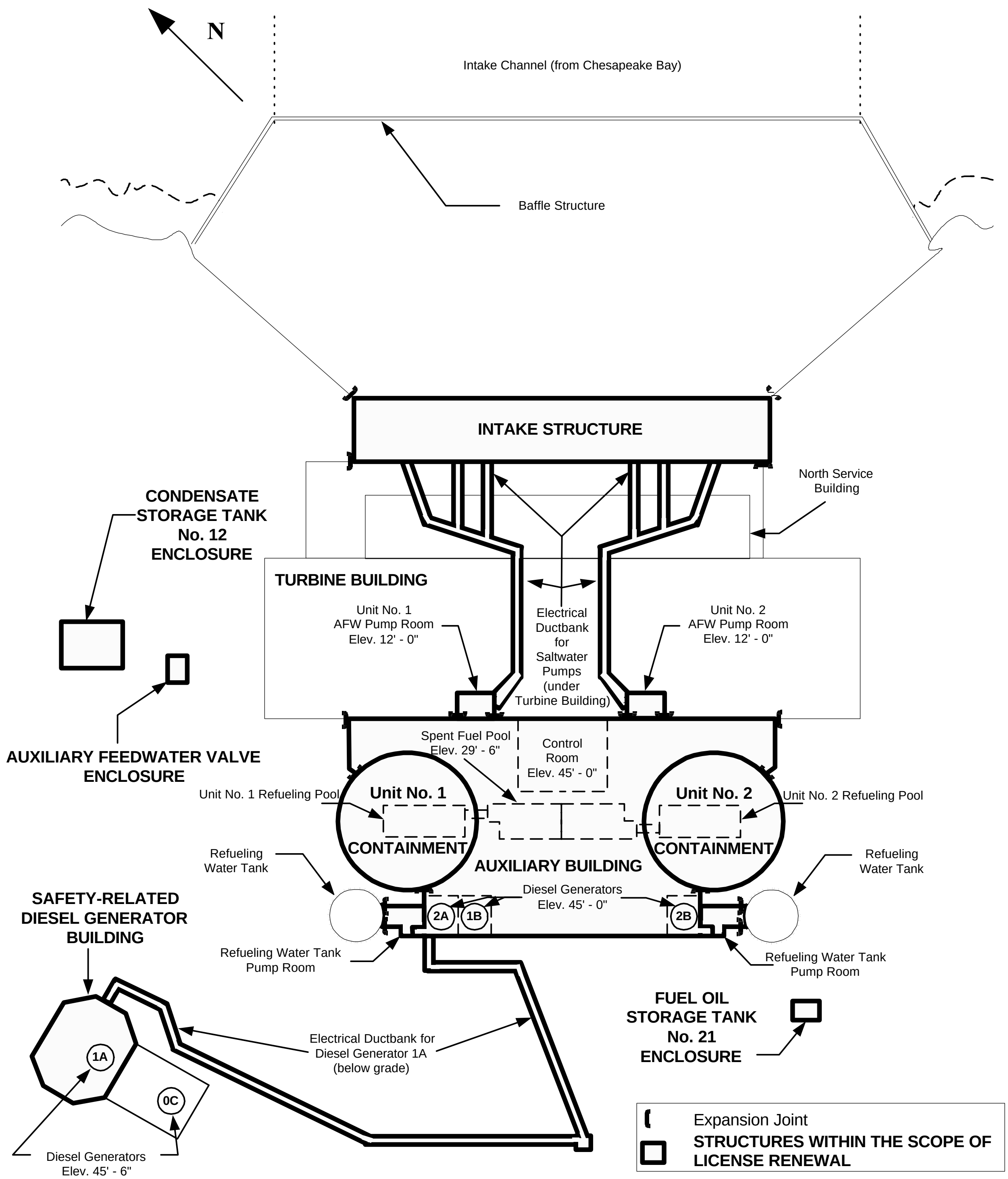

FIGURE 3.3E-1
CCNPP SITE STRUCTURES
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

Component supports that are connected to structural components in the Auxiliary Building and SR Diesel Generator Building Structures are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. A "component support" is the connection between a system, or component within a system, and a plant structural member. Component supports interface with the components they support in the applicable systems, and they interface with the structural component to which they are attached. For example, a fixed base supporting a pump is considered a component support since it connects the concrete equipment pad to the pump. The pump itself would be scoped within its associated system evaluation. The fixed base would be scoped within the Component Supports Commodity Evaluation, and the concrete equipment pad would be scoped within the evaluation for the associated structure. If anchor bolts are used at the interface with the structural member, there is overlap between the Component Supports Commodity Evaluation and the evaluation for the structural component. Evaluations for structural components considered the effects of aging caused by the surrounding environment, while the Component Supports Commodity Evaluation considered the effects of aging caused by the supported equipment (thermal expansion, rotating equipment, etc.), as well as the surrounding environment. Supports for structural components (e.g., platform hangers) are not "component supports" in this sense because any support for a structural component is itself a structural component (i.e., included in the scope of the associated structure). [Reference 13, Section 1.1.1]

Cranes that routinely lift heavy loads over SR components in the Auxiliary Building and components involved in fuel handling and transfer in and around the SFP are evaluated for the effects of aging in the Fuel Handling Equipment and Other Heavy Load Handling Cranes Commodity Evaluation in Section 3.2 of the BGE LRA. [Reference 1, Section 7.2.2] The following structural component types in the Auxiliary Building interface with cranes and fuel handling equipment and are evaluated in this section:

Spent fuel cask handling crane rail/supports (girders)	-	interface with carbon steel crane rails;
SFP reinforced concrete	-	interfaces with spent fuel handling machine carbon steel rails, transfer machine jib crane structural members;
SFP stainless steel liner	-	interfaces with structural members of the spent fuel shipping cask platform, incore instrumentation trash racks, SFP platform, spent fuel inspection elevators fuel upending machine and transfer carriage; and
Spent fuel and new fuel storage racks	-	interface with fuel assemblies.

Scoped Structures and Their Intended Functions

The Auxiliary Building and SR Diesel Generator Building Structures are in scope for license renewal based on 10 CFR 54.4(a). All seven generic structural functions listed above are applicable to these structures as shown in Table 3.3E-1. The intended functions for these enclosures were determined based on the requirements of §54.4(a)(1), §54.4(a)(2), and §54.4(a)(3), in accordance with the CCNPP IPA Methodology Section 4.2.2. [Reference 1; Reference 2, Table 2; Reference 7, Section 1.1.3; Reference 12, Appendix B4, Section 1.3]

TABLE 3.3E -1
INTENDED FUNCTIONS FOR THE AUXILIARY BUILDING AND SR DIESEL GENERATOR BUILDING STRUCTURES

Function	Applicable to Auxiliary Building & Adjacent Rooms?	Applicable to SR Diesel Generator Building?	Applicable to ductbank for EDG 1A?	Applicable 10 CFR 54.4(a) Criteria
1. Provide structural and/or functional support to SR equipment	Yes	Yes	Yes	§54.4(a)(1)
2. Provide shelter/protection to SR equipment NOTE: The SR Diesel Generator Building and the ductbank for EDG 1A are not required to provide protection from radiation or high energy line break effects.	Yes	Yes	Yes	§54.4(a)(1)
3. Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated DBEs	Yes	No	No	§54.4(a)(1)
4. Serve as a missile barrier (internal or external)	Yes	Yes	Yes	§54.4(a)(1)
5. Provide structural and/or functional support to NSR equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions (e.g., seismic Category II over I design considerations)	Yes	Yes	No	§54.4(a)(2)
6. Provide flood protection barrier (internal flooding event)	Yes	Yes	No	§54.4(a)(2)
7. Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant	Yes	Yes	No	§54.4(a)(3)

Components Subject to AMR

A generic list of structural component types was developed for use during the structural component scoping task. The generic list started with structural component types associated with SR functions contained in industry technical reports addressing Containment and Category I Structures. Other structural component types related to fire and flooding events were added to the list to ensure completeness. [Reference 1, Section 4.2.3] These structural components were combined into the following four structural categories based on their design and materials: [Reference 12, Appendix B4, Section 2.0; Reference 14]

- Concrete components;
- Structural steel components;
- Architectural components; and
- Unique components.

During the scoping process, applicable structural component types actually contained in the Auxiliary Building and SR Diesel Generator Building Structures were identified. Within the four structural component categories, 47 structural component types were determined to contribute to at least one of the structural intended functions listed in Table 3.3E-1 for the associated structure. Table 3.3E-2 lists the structural component types and the associated functions that apply to the Auxiliary Building, the adjacent

EDG Rooms and RWT Pump Rooms, the SR Diesel Generator Building, and the ductbank for EDG 1A. Unless otherwise noted, structural components that are part of the structure, but do not contribute to any of the intended functions of the structure, are not listed in Table 3.3E-2. [References 4 and 5; Reference 7, Table 2-1; Reference 12, Appendix B4, Section 2.0; References 14 through 17]

Per the license renewal rule, ". . . Structures and components subject to an aging management review shall encompass those structures and components (i) That perform an intended function, as described in §54.4 without moving parts or without a change in configuration or properties . . . and (ii) That are not subject to periodic replacement based on a qualified life or specified time period . . . " From reviewing the generic list of structural functions, it is clear that none of the intended structural functions requires moving parts or a change in configuration or properties. Plant structural components are not normally subject to periodic replacement programs; therefore, they are considered to be long-lived unless specific justification is provided to the contrary. [Reference 1, Section 5.4]

Of the 47 structural component types within the scope of license renewal for the Auxiliary Building and SR Diesel Generator Building Structures, one unique component type, Pipe Encapsulations, was evaluated in the AMR for the Main Steam System; the results of the AMR for these components are presented in Section 5.12 of the BGE LRA. The remaining 46 structural component types, listed in Table 3.3E-2, are subject to AMR and are evaluated within this section. [Reference 7, Table 2-1; Reference 12, Appendix B4, Table 2-1 and Section 4.2.4]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies that further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

TABLE 3.3E-2
STRUCTURAL COMPONENT TYPES REQUIRING AMR FOR THE AUXILIARY BUILDING AND SR DIESEL GENERATOR BUILDING STRUCTURES

	Auxiliary Building & Adjacent Rooms	SR Diesel Generator Building	ductbank for EDG 1A
Concrete (Including Reinforcing Steel)			
Foundations (Footings, beams, and mats)	1, 5	1, 5	NA
Columns,	1, 5	1, 5	NA
Walls	1, 2, 4, 5, 6, 7	1, 2, 4, 5, 6, 7	NA
Beams,	1, 5	1, 5	NA
Ground Floor Slabs	1, 5	1, 5	NA
Equipment Pads	1, 5	1, 5	NA
Elevated Floor Slabs	1, 2, 5, 7	1, 2, 5, 7	NA
Roof Slabs	2, 4	2, 4	NA
Cast-In-Place Anchors/Embedments*	1	1	1, 2, 4
Manholes	NA	NA	1, 2
Ductbanks	NA	NA	1, 2
Grout	1, 5	1, 5	NA
Concrete Blocks (Shielding)	2	NA	NA
Fluid Retaining Walls and Slabs	1	1	NA
Masonry Block Walls	1, 2, 5, 6, 7	NA	NA
Post-Installed Anchors*	1, 5	1, 5	2, 4
Structural Steel			
Columns*, Beams*, Baseplates*, Floor Framing*	1, 5	1, 5	NA
Roof Framing*, Roof Trusses*	1, 4, 5	1, 4, 5	NA
Bracing*, Platform Hangers*, Decking*	1, 5	1, 5	NA
Jet Impingement Barriers*	2	NA	NA
Liners*	3	NA	NA
Architectural Components			
Fire Doors, Jambs, and Hardware*	7	7	NA
Access Doors, Jambs, and Hardware*	2	2	NA
Caulking and Sealants	2, 6, 7	2, 6, 7	NA

TABLE 3.3E-2 (continued)
STRUCTURAL COMPONENT TYPES REQUIRING AMR FOR THE AUXILIARY BUILDING AND SR DIESEL GENERATOR BUILDING STRUCTURES

	Auxiliary Building & Adjacent Rooms	SR Diesel Generator Building	ductbank for EDG 1A
Unique Components			
New Fuel Rack Assembly*, Spent Fuel Storage Racks (Carborundum sheets, Boraflex sheets)	1	NA	NA
Monorail*	5	5	NA
Cask Handling Crane Rail/Supports*	1, 5	NA	NA
Lead Brick Shielding, Pipe Whip Restraints*	2	NA	NA
Roll-Up Doors*	2	2	NA
Expansion Joints	2, 7	2, 7	NA
Watertight Doors*	6, 7	NA	NA
Pipe Encapsulations	2 (Note 1)	NA	NA
Missile Protection Doors*	4	4	NA
Gypsum Board	7	NA	NA
Handholes	NA	NA	1, 2
Hole Framing*, Manhole Covers*, Cover Plates*	NA	NA	2, 4
Missile Shields*	NA	NA	4

* - Indicates the component type is included under the heading "Steel Components" in the discussion addressing the results of AMR in Table 3.3E-3

(#) - Indicates the component type provides the following intended function for the corresponding structure:

1 - Provide structural and/or functional support to SR equipment;
2 - Provide shelter/protection to SR equipment;
3 - Serve as a pressure boundary or a fission product retention barrier to protect public health and safety in the event of any postulated DBEs;
4 - Serve as a missile barrier (internal or external);
5 - Provide structural and/or functional support to NSR equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions;
6 - Provide flood protection barrier (internal flooding event); and
7 - Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant.

none - Indicates the component type does not contribute to the intended functions of the structure

NA - Indicates the component type is not part of the corresponding structure

Note 1 - These structural component types are also identified as device types in the Chemical and Volume Control, Feedwater, and Main Steam Systems at CCNPP. The results of the AMR for these components are presented in Section 5.12 of the BGE LRA. [Reference 7, Table 2-1]

3.3E.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for components in the Auxiliary Building and SR Diesel Generator Building Structures is given in Table 3.3E-3, with plausible ARDMs identified by a check mark (✓) in the appropriate column. [Reference 7, Attachments 1 and 2; Reference 12, Appendix B4, Section 4.0] For efficiency in presenting the results of these evaluations in this report, ARDM/component type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components. Table 3.3E-3 also identifies the group to which each ARDM/component type combination belongs. The following groups have been selected for the Auxiliary Building and SR Diesel Generator Building Structures:

Group 1: weathering of caulking, sealants, and expansion joints;

Group 2: corrosion of steel (for components marked with an asterisk in Table 3.3E-2);

Group 3: corrosion of the SFP liner (sensitized zones); and

Group 4: degradation of neutron-absorbing materials (for SFP storage racks).

Aging mechanisms that are not plausible are generally not discussed further in these BGE LRA sections, unless they are considered noteworthy. For the Auxiliary Building and SR Diesel Generator Building Structures, settlement is considered noteworthy and is discussed below.

Industry technical reports conclude that settlement is a potentially significant ARDM for pressurized-water reactor Containment Structures and for other Category I Structures at some plants. [Reference 18, Section 5.5; Reference 19, Section 5.1.2] Settlement occurs both during construction and after construction. The amount of settlement depends on the physical properties of the foundation material. [Reference 7, Appendix J] Excavation unloading and structural loading during construction caused a small change in the void ratio of undisturbed soil. This change results in a very small or negligible amount of time-dependent settlement. [Reference 6, Section 2.7.6.2; Reference 7, Appendix J] Compacted soil is subject to some degree of settlement in the first several months after construction. [Reference 19, Section 4.6.3.1] Settlement directly related to construction work is readily evident early in the life of the structure and is not considered to be an ARDM. Settlement may occur during the design life of the structure from changes in environmental conditions, such as lowering of the groundwater table. Sites with soft soil and/or sites with significant changes in underground water conditions over a long period of time may be susceptible to significant settlement. [Reference 7, Appendix J; Reference 18, Section 4.5.3.2; Reference 19, Section 4.6.3.2] Concrete and steel structural members can be affected by differential settlement between supporting foundations, within a building, or between buildings. Severe settlement can cause misalignment of equipment and lead to overstress conditions within the structure. When buildings experience significant settlement, cracks in structural members, differential elevations of supporting members bridging between buildings, or both may be visibly detected. [Reference 7, Appendix J] At CCNPP, long-term settlement was determined to be not plausible for the Auxiliary Building and SR Diesel Generator Building Structures based on the following site-specific justification:

TABLE 3.3E-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE AUXILIARY BUILDING AND SR DIESEL GENERATOR BUILDING STRUCTURES

Potential ARDMs	Concrete (Including Reinforcing Steel)**	Steel Components*	Spent Fuel Pool Liner	Expansion Joints, Caulking and Sealants	Spent Fuel Storage Racks***	Lead Brick Shielding	Gypsum Board
Freeze-Thaw							
Leaching of Calcium Hydroxide							
Aggressive Chemical Attack on Concrete							
Corrosion of Embedded Steel/Rebar							
Cracking of Masonry Block Walls							
Settlement							
Corrosion of Steel		✓(2)					
Corrosion of Liners			✓(3)				
Weathering				✓(1)			
Elevated Temperature							
Irradiation							
Fatigue							
Degradation of Carborundum Material					✓(4)		
Degradation of Boraflex Material					✓(4)		

* - "Steel Components" represents all items marked with an asterisk (*) in Table 3.3E-2

** - "Concrete (Including Reinforcing Steel)" comprises Foundation Mat, Concrete Columns, Ground Floor Slabs, Equipment Pads, Elevated Floor Slabs, Concrete Walls, Concrete Beams, Roof Slabs, Manholes, Ductbanks, Handholes, Grout, Concrete Blocks (Shielding), Masonry Block Walls, Fluid Retaining Walls and Slabs

*** - Includes stainless steel, Carborundum sheets (Unit 1 only), and Boraflex sheets (Unit 2 only)

✓ - Indicates plausible ARDM determination **(#)** - Indicates the group(s) in which the ARDM/component type combination is evaluated

- The foundation materials supporting the Auxiliary Building and SR Diesel Generator Building Structures have varying physical properties. The foundation for the Auxiliary Building is situated primarily on the undisturbed soil of the site's Miocene deposit, which is an exceptionally dense soil that is capable of supporting loads on the order of 15,000 to 20,000 pounds per square foot (psf). [Reference 6, Section 2.7.3; Reference 7, Appendix J] The design contact pressure of the Auxiliary Building mat is only 8,000 psf. This contact pressure is about the same as the weight of soil removed by site grading and pit excavation for the structure. [Reference 1, Sections 2.7.5 and 2.7.6.2; Reference 7, Appendix J] For the SR Diesel Generator Building, the ductbank for EDG 1A, the EDG Rooms adjacent to the Auxiliary Building, and each Unit's RWT Pump Room, engineered soil structures incorporating compacted fill materials (e.g., crushed stone, compacted soil and/or concrete) provide foundation support. [Reference 7, Appendix J; References 8, 9, and 20; Reference 21, Sections 2.3.2 and 2.3.3] Quality assurance and quality control measures imposed during backfill placement included specification of maximum lift thicknesses and verification of minimum fill compaction. Beneath the SR Diesel Generator Building, crushed stone was compacted to 95 percent of maximum dry density based on the modified Proctor compaction method; similarly, the bedding material supporting the ductbank for EDG 1A was compacted to 90 percent. [References 22 and 23] Under the rooms adjacent to the Auxiliary Building, fill was compacted to 97 percent based on the standard Proctor compaction method. [References 8, 9, 24, and 25] For each of the structures constructed on compacted fill, a continuous program of soil testing during construction assured uniform placement of the material. [References 23 and 26] These activities assured that the causes of excessive settlement of plant structures at other nuclear power plant sites did not exist during construction at CCNPP. [Reference 27] Control of the placement and compaction for these engineered soil structures was used to obtain the engineering properties required to satisfy foundation design requirements.

- A stable groundwater table exists in the vicinity of the Auxiliary Building and SR Diesel Generator Building Structures. A permanent pipe drain system surrounding the plant, including the Auxiliary Building and adjacent rooms, is designed to maintain the groundwater table below Elevation 10'-0"; this minimizes any changes to the site conditions that could affect settlement of the foundations for these structures. [Reference 6, Section 2.7.3; Reference 28] The foundation for the SR Diesel Generator Building and the ductbank for EDG 1A are situated outside the boundary of the permanent pipe drain system. [References 4, 5, 15, 16, and 17; Reference 21, Section 2.3.2] The elevation of the groundwater table beneath these structures changes with the surface topography and can be expected to fluctuate slightly as a result of climatic changes. [Reference 6, Section 2.5.3.3] However, significant deviations from the seasonal cycles and occasional meteorological effects (e.g., drought conditions) observed over the past 25 years are not expected during the period of extended operation.

- The foundations for the Auxiliary Building and SR Diesel Generator Building Structures tend to uniformly settle as rigid bodies. [Reference 7, Appendix J; Reference 12, Appendix B4, Table 4-1] Most of the predicted settlement is expected in terms of uniform settlement, which has no adverse effect on structural components of the Auxiliary Building, the SR Diesel Generator Building, or the ductbank for EDG 1A. [Reference 7, Appendix J; Reference 12, Appendix B4, Table 4-1] A sand pocket is incorporated into the design of the ductbank for EDG 1A at its junction with the SR Diesel Generator Building to accommodate the effects of differential settlement on the associated conduit. The effects of one-time building settlement are included in the stresses allowed by design codes and standards for piping systems. Any differential settlement is expected to be small and have negligible effect.

At CCNPP, no cracking or other evidence of settlement that would affect structural integrity has been observed to date. A walkdown inspection of the Auxiliary Building, performed in 1994, found no indication of structural damage due to settlement. [Reference 7, Attachment 7] These observations support the conclusion that settlement of the Auxiliary Building and SR Diesel Generator Building Structures at CCNPP is not plausible.

The following is a discussion of the aging management demonstration process for each group identified in Table 3.3E-3. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

Group 1 - (weathering of caulking, sealants, and expansion joints) - Materials and Environment

The structural component types affected by weathering include caulking, sealants, and expansion joints used in the Auxiliary Building and SR Diesel Generator Building Structures. By accommodating thermal and seismic movement without exceeding allowable stresses, expansion joints contribute to providing shelter/protection to the SR equipment inside reinforced concrete structures. Elastic caulking and sealant materials are used to fill these joints, as well as barrier penetration seals for piping or conduits that run through structural concrete surfaces. These materials prevent the passage of steam or water through building joints during a high energy line break or flooding event. When any of these structural component types are installed in a fire barrier, they also contribute to performance of the structure's fire protection function. [Reference 7, Appendix O; Reference 14, Table 3S]

The material requirements for the caulking, sealants, and expansion joints used during construction of CCNPP were governed by construction specifications. Individual products were specified by manufacturer and brand name (or approved equivalent) for particular applications. [References 29 and 30]

The caulking, sealants, and expansion joints located indoors are exposed to temperature and humidity conditions inside the Auxiliary Building and SR Diesel Generator Building Structures as described in UFSAR Chapter 9. [Reference 6, Section 9.8.2.3 and Table 9-18] The caulking, sealants, and expansion joints located outdoors are subject to the normal outside atmosphere at the CCNPP site. The CCNPP site is located in a geographic region subject to severe weather conditions. All outdoor components will experience the extreme temperature ranges, rain, snow, and changes in humidity expected at the CCNPP site. [Reference 7, Appendix O]

Group 1 - (weathering of caulking, sealants, and expansion joints) - Aging Mechanism Effects

Caulking, sealants, and expansion joints that are exposed to ambient conditions (indoor or outdoor) are susceptible to degradation due to weathering. Exposure to sunlight (ultraviolet exposure), changes in humidity, ozone cycles, snow, rain, ice, and temperature and pressure fluctuations contribute to the weathering ARDM. The effects of weathering on most materials, including caulking, sealant, and expansion joint materials, are evidenced by a decrease in elasticity (e.g., drying out), an increase in hardness, and shrinkage. [Reference 7, Appendix O]

Expansion joints between the Containment structures and the EDG Rooms adjacent to the Auxiliary Building have experienced age-related degradation in the past. The affected joints were subsequently repaired using approved sealant materials.

Weathering is plausible for the caulking, sealants, and expansion joints used in the Auxiliary Building and SR Diesel Generator Building Structures because they are exposed to the environmental conditions that contribute to this ARDM. If left unmanaged for an extended period of time, these materials will become brittle and lose their capability to perform their intended functions under current licensing basis (CLB) conditions. [Reference 7, Appendix O]

Group 1 - (weathering of caulking, sealants, and expansion joints) - Methods to Manage Aging

Mitigation: Because weathering of caulking, sealants, and expansion joints is affected by exposure to environmental conditions that are not feasible to control (e.g., light, heat, oxygen, ozone, water, radiation), there are no practical methods to mitigate its effects.

Discovery: Caulking, sealants, and expansion joints degrade over time and should be replaced as needed. An inspection program that provides requirements and guidance for the identification, inspection, and maintenance of caulking, sealants, and expansion joints can ensure that their condition is maintained at a level that allows them to perform their intended functions. An effective program will provide for baseline inspection along with periodic future inspections at appropriate intervals depending upon the degree of harshness of the environment of the caulking, sealant, or expansion joint. Items that are in a harsh exterior environment would be inspected more frequently. This program would involve visual inspection and probing to determine that the caulking, sealant, or expansion joint is satisfactorily attached to the surface and is flexible.

Group 1 - (weathering of caulking, sealants, and expansion joints) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited for mitigation of weathering.

Discovery: Caulking, sealants, and expansion joints that perform a fire barrier function in the Auxiliary Building, the adjacent EDG Rooms, and the RWT Pump Rooms, are managed under an existing program. The Penetration Fire Barrier Inspection Program, implemented through CCNPP Technical Procedure STP-F-592-1/2, is adequate to manage the effects of aging for caulking, sealants, and expansion joints that function as fire barriers without modification. [Reference 7, Section 5.2.1].

The purpose of STP-F-592-1/2 is to provide instructions for visual inspection of fire barrier penetration seals in fire area boundaries that protect safe shutdown areas in Units 1 and 2. The scope of this procedure is to visually inspect the following type of fire barrier penetration seals for operability: [References 31 and 32, Sections 1.0 and 2.2]

- Electrical conduit and cable tray penetration seals;
- Heating, ventilation, and air conditioning duct penetration seals (ducts without dampers); and
- Mechanical pipe and expansion joint penetration seals.

Procedure STP-F-592-1/2 was developed based on CCNPP Technical Specifications 3.7.12 and 4.7.12.a, 10 CFR Part 50 Appendix R, the CCNPP Fire Protection Plan, NRC Generic Letter 86-10, "Implementation of Fire Protection Requirements," and various plant drawings. [References 31 and 32, Section 3.1]

The procedure is performed at least once every 18 months in accordance with Technical Specification 4.7.12.a. The procedure requires that the fire barrier penetration seals be visually inspected to determine if they are operable based on specific criteria that were developed for each type of fire barrier component. In general, the procedure inspects the penetration seals for damage, cracking, voids, and proper installation. The procedure provides separate "failure criteria" and "repair criteria." The "failure criteria" are used to determine if the penetration seal is considered to be inoperable. The "repair criteria" are used to determine if the penetration seal is operable but in need of repair. [References 31 and 32, Sections 2.1 and 6.0, and Attachment A]

If a fire barrier penetration seal is determined to be inoperable based on the procedure criteria, plant personnel determine if actions are required in accordance with Technical Specification 3.7.12.a. In addition, any conditions adverse to quality discovered during the inspection are documented on Issue Reports in accordance with the CCNPP Corrective Actions Program. [References 31 and 32, Section 6.5 and Attachment B]

The Fire Protection Program at CCNPP (which includes STP-F-592-1/2) is subject to periodic internal assessment in accordance with the requirements in BGE's Quality Assurance Policy. Audits are required for the Fire Protection Program and implementing procedures every two years. In addition, an independent fire protection and loss prevention program inspection and audit utilizing either qualified offsite BGE personnel or an outside fire protection firm is required every two years. The Quality Assurance Policy also requires an inspection and audit of the fire protection and loss prevention program by a qualified outside fire consultant at least once every three years. An audit and inspection performed in 1996 (using an outside consultant as well as BGE personnel) concluded that the CCNPP Fire Protection Program is providing a level of safety consistent with good fire protection practices and NRC regulatory criteria. The inspection included plant walkdowns of some of the fire barrier penetration seals. No age-related degradation issues for the seals were identified. [Reference 33, Section 1B.18]

The Fire Protection Program has been evaluated by the NRC as part of its routine licensee assessment activities. An inspection of the program in 1994 included a review of procedure STP-F-592-1 and a plant tour that included inspection of some of the fire barrier penetrations. The NRC concluded that the Fire Protection Program complies with program requirements provided in the Technical Specifications and licensing documents. [References 34 and 35]

Operating experience related to this program has shown that aging is a minor contributor to fire barrier penetration seal failures at CCNPP. The greatest contributor to degradation of these seals is believed to be inadequate technique used in the original installation of the seal materials.

The corrective actions taken as a result of the Penetration Fire Barrier Inspection Program will ensure that the caulking, sealants, and expansion joints in the Auxiliary Building and adjacent rooms that perform a fire barrier function will remain capable of performing their intended function under all CLB conditions.

Caulking, sealants, and expansion joints that are not included in the Penetration Fire Barrier Inspection Program are typically replaced upon identification of their degraded condition. Visual examinations of the caulking, sealants, and expansion joints in the plant concluded that an inspection program was needed to adequately manage the aging of these structural component types. [Reference 7, Appendix O]

For the caulking, sealants, and expansion joints in the SR Diesel Generator Building, as well as for those in the Auxiliary Building and adjacent rooms that do not perform a fire barrier function, a new CCNPP Caulking and Sealant Inspection Program will provide requirements and guidance for the identification, inspection frequencies, and acceptance criteria for caulking, sealants, and expansion joints to ensure that their condition is maintained at a level that allows them to perform their intended functions. The new program will establish acceptance criteria and require a baseline inspection to determine the material condition of the caulking, sealants, and expansion joints for the Auxiliary Building and SR Diesel Generator Building. If unacceptable degradation exists, corrective actions will be taken. A technical basis will be developed for determining the periodicity of future inspections. [Reference 7, Section 5.2.3 and Attachment 8]

Group 1 - (weathering of caulking, sealants, and expansion joints) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to weathering of caulking, sealants, and expansion joints:

- Caulking, sealants, and expansion joints in the Auxiliary Building and SR Diesel Generator Building Structures contribute to providing shelter/protection to SR equipment inside the structures. Some caulking and sealants also provide flood protection barriers. When used in fire barriers, all of these component types also contribute to the structures' fire protection functions. Therefore, the condition of caulking, sealants, and expansion joints must be maintained under all CLB design conditions.
- Caulking, sealant, and expansion joint materials are subject to weathering when exposed to normal indoor and outdoor conditions at the CCNPP site. If unmanaged, this ARDM could result in these components losing their capability to perform their intended functions under CLB design loading conditions.
- For caulking, sealants, and expansion joints that function as fire barriers in the Auxiliary Building and adjacent rooms, the Penetration Fire Barrier Inspection Program performs periodic visual inspections of fire barrier penetration seals, and contains acceptance criteria that ensure corrective actions will be taken such that the fire barrier intended function will be maintained.
- For caulking, sealants, and expansion joints in the SR Diesel Generator Building, as well as for those in the Auxiliary Building and adjacent rooms that do not perform a fire barrier function, a new Caulking and Sealants Inspection Program will conduct inspections to detect age-related degradation, and will contain acceptance criteria that ensure corrective actions will be taken such that the intended functions will be maintained.

Therefore, there is a reasonable assurance that the effects of weathering will be adequately managed for the caulking, sealants, and expansion joints in the Auxiliary Building and SR Diesel Generator Building Structures such that they will be capable of performing their intended functions consistent with the CLB during the period of extended operation under all design loading conditions.

Group 2 - (corrosion of steel) - Materials and Environment

Group 2 comprises those components marked with an asterisk in Table 3.3E-2. These components are all fabricated from carbon steel, which is subject to general corrosion when exposed to moisture and oxygen. They each contribute to one or more of the various passive intended functions for the Auxiliary Building and SR Diesel Generator Building Structures. The environment to which these components are subjected varies with their installed location. Component types located indoors are exposed to temperature and humidity conditions inside the Auxiliary Building and SR Diesel Generator Building Structures as described in UFSAR Chapter 9. [Reference 6, Section 9.8.2.3 and Table 9-18] Those steel component types located outdoors are subject to the normal outside atmosphere at the CCNPP site. [Reference 7, Appendix K] There is no heavy industry nearby CCNPP to add chemicals to the atmosphere but, due to the close proximity of the Chesapeake Bay, the steel components located outdoors could be exposed to condensation. [Reference 6, Sections 2.8 and 2.10; Reference 7, Appendix C] Some of the steel components are located near the SFP, where condensation in the presence of oxygen could lead to oxidation. Carbon steel located in these areas may be subjected to more severe local environments. [Reference 7, Appendix K]

Since corrosion was recognized as a potential degradation mechanism for all carbon steel components of site structures, protective coatings were incorporated into the original design. Exposed structural steel surfaces in the Auxiliary Building and SR Diesel Generator Building Structures were coated during the construction phase (e.g., shop-primed, field-painted, hot-dipped galvanized). [Reference 7, Appendix K; References 36 through 43]

Group 2 - (corrosion of steel) - Aging Mechanism Effects

Steel corrodes in the presence of moisture and oxygen as a result of electrochemical reactions. Initially, the exposed steel surface reacts with oxygen and moisture to form an oxide film as rust. Once the protective oxide film has been formed, and if it is not disturbed by erosion, alternating wetting and drying, or other surface actions, the oxidation rate will diminish rapidly with time. Chlorides, either from saltwater, the atmosphere, or groundwater, increase the rate of corrosion by increasing the electrochemical activity. If steel is in contact, through an electrolytic solution, with another metal that is more noble in the galvanic series, corrosion of the steel may accelerate. [Reference 7, Appendix K]

Corrosion products such as hydrated oxides of iron (rust) form on exposed, unprotected surfaces of the steel and are readily visible. The affected surface may degrade to such an extent that visible perforation may occur. In the case of exposed surfaces of steel with protective coatings, corrosion may cause the protective coatings to lose their ability to adhere to the corroding surface. In this case, damage to the coatings can be visually detected well in advance of significant degradation of the steel. [Reference 7, Appendix K]

If corrosion is left unmanaged for an extended period of time, the loss of carbon steel material can result in a reduction in the load-bearing capability of the corroded parts and increased likelihood of mechanical failure. This could lead to the inability of components identified in Table 3.3E-2 to perform their intended functions under CLB design loading conditions. [Reference 7, Appendix K]

Group 2 - (corrosion of steel) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment and protecting the external surfaces with paint or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces.

Discovery: The effects of general corrosion/oxidation of carbon steel are detectable by visual inspection. A visual examination by a person familiar with the components can be used to determine general mechanical and structural condition and check for rust. Observing that significant degradation of protective coatings has not occurred is an effective method to ensure that corrosion has not affected the intended function of the structural component. Since the coating does not contribute to the components' intended functions, degradation of the coating provides an alert condition that triggers corrective action before the occurrence of corrosion that would affect the components' ability to perform their intended functions. The degradation of the protective coating that does occur can be discovered and monitored by periodically inspecting the carbon steel structural components. Corrective action for failed protective coatings and any actual metal degradation can be carried out as necessary. [Reference 7, Appendix K]

Group 2 - (corrosion of steel) - Aging Management Programs

Mitigation: The exposed metal surfaces of carbon steel structural components are covered by protective coatings that mitigate the effects of corrosion. The discovery programs discussed below verify that the protective coatings of carbon steel structural components are maintained.

Discovery: Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of corrosion of steel (or conditions that would accelerate corrosion, such as pooled water) for the structural components in the Auxiliary Building and SR Diesel Generator Building Structures by performance of visual inspections during plant walkdowns. [Reference 7, Attachment 4; Reference 12, Appendix B4, Section 4.2.5] The purpose of the program is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. [Reference 44, Section 1.1]

Under this program, responsible personnel perform periodic walkdowns of their assigned structures and systems. Walkdowns may also be performed as required for reasons such as: material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when the system is initially pressurized, energized, or placed in service); and as required for plant modifications. [Reference 44, Section 5.1]

One of the objectives of the program is to assess the condition of the CCNPP structures, systems, and components such that any abnormal or degraded condition will be identified, documented, and corrective actions taken before the condition proceeds to failure of the structures, systems, and components to perform their intended functions. Conditions adverse to quality are documented and resolved by the CCNPP Corrective Actions Program. [Reference 44, Sections 5.1.C, 5.2.A.1, and 5.2.A.5]

The program provides guidance for identification of specific types of degradation or conditions when performing the walkdowns. Inspection items related to aging management include the following: [Reference 44, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

The Structure and System Walkdown Program enhances the familiarity of responsible personnel with their assigned systems and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance personnel alone. The program has been improved recently through incorporation of significant additional guidance on specific activities to be included in the scope of structures walkdowns. A structure performance assessment is currently required for Category I structures at CCNPP at least once every six years. The assessment includes a review of each structural component that could degrade the overall performance of the structure. [Reference 44, Section 5.3 and Attachments 4 and 8]

The program described above will be modified to: (a) specifically identify the carbon steel component types within the scope of the performance assessments (including those identified in Table 3.3E-2 as unique structural component types); and (b) add guidance regarding approval authority for significant departures from the walkdown scope/schedule specified. The modified program will ensure that degraded conditions due to corrosion of steel are identified and corrected such that carbon steel components of the Auxiliary Building and SR Diesel Generator Building Structures will be capable of performing their intended functions consistent with CLB design conditions.

Group 2 - (corrosion of steel) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of steel in the structural components of the Auxiliary Building and SR Diesel Generator Building Structures:

- The carbon steel components identified in Table 3.3E-2 provide various passive intended functions for the associated structures, and failure could directly prevent satisfactory accomplishment of functions that must be maintained under CLB design loading conditions.
- Components in this group are exposed to moisture and oxygen in their installed locations.
- Carbon steel corrodes in the presence of moisture and oxygen, which leads to a loss of material. This could eventually result in inability of the affected components to perform their intended function(s).
- Coatings, specified during original construction, mitigate the effects of corrosion by providing a protective layer that prevents moisture and oxygen from contacting the steel.
- The CCNPP Structure and System Walkdowns Program provides for periodic walkdowns of Group 2 components. The program will be modified to specify more clearly the scope and control of periodic performance assessments. The program will provide for the discovery of corrosion of steel (or conditions that would accelerate corrosion) for the components in Group 2, and ensure

appropriate actions are taken in a timely manner to correct degraded components or protective coatings.

Therefore, there is reasonable assurance that the effects of aging due to corrosion of carbon steel will be managed in such a way that structural components of the Auxiliary Building and SR Diesel Generator Building Structures will be capable of performing their intended functions consistent with the CLB during the period of extended operation.

Group 3 - (corrosion of the SFP liner) - Materials and Environment

The SFP liner at CCNPP is constructed of Type 304 stainless steel material. [Reference 7, Appendix L; Reference 45] The liner was assembled from a series of individual plates that were welded together. The stainless steel liner is not a load-bearing structural component; it was designed only as a leaktight barrier serving a pressure boundary function. [Reference 7, Table 2-1 and Appendix L; Reference 45] One side of the SFP liner is normally exposed to the borated water contained inside the pool; the other side of the SFP liner conforms to a reinforced concrete wall. [Reference 7, Appendix L]

The concrete behind the welds was formed such that a small trough or channel was created to allow detection of any leakage that may occur through the welds or liner. Individual channels are grouped into leak chases that are each connected to a hand valve through a short piping system. There are a total of ten such “telltale” valves for the SFP (four for leak chases from vertical plates and one for the floor leak chase in each Unit’s side of the SFP). [Reference 7, Appendix L; References 46 through 49]

Water has been collected from these leak chases monthly for many years. [Reference 7, Attachment 5 and Appendix L] The total leakage measured each month averages about 0.1 gallons in a 24-hour period. Due to the small sample size and other interfering factors, it is difficult to confirm the SFP liner as the source of the water collected during the monthly testing; frequently, no water leakage is observed during the test. [Reference 7, Appendix L] In 1995, the source of water collected from one of the “telltale” valves was determined to be from the Unit 2 SFP.

Group 3 - (corrosion of the SFP liner) - Aging Mechanism Effects

Both the plate material and the associated weld materials are susceptible to stress corrosion cracking, which is defined as cracking under the combined actions of corrosion and tensile stresses. The stresses may be applied (external) or residual (internal), and the cracks themselves may be transgranular or intergranular. [Reference 7, Appendix L] Type 304 stainless steels are particularly prone to this ARDM in locations that are sensitized, such as heat-affected zones in and around welds and at crevice geometries. This is because of the changes in the material’s microstructure that take place due to the welding heat, and because of high residual stresses in and around the welds. [Reference 19, Section 4.5.1.1] Under such conditions, Type 304 stainless steel may develop intergranular stress corrosion cracking (IGSCC). [Reference 7, Appendix L]

The SFP liner was not designed to carry significant structural loads, and the strains induced by conforming to deformations in the concrete wall of the SFP are negligible under normal plant operating conditions. The liner is not exposed to a corrosive environment under normal operating conditions. Therefore, the conditions necessary for stress corrosion cracking do not exist for the SFP liner. [Reference 7, Appendix L]

However, the heat-affected zones in and around welds joining the liner plates are potential sites for sensitization. Conditions that may contribute to the occurrence of IGSCC include elevated temperatures, chloride content, boric acid concentration, oxygen concentration, and degree of sensitization. [Reference 7, Appendix L; Reference 19, Section 4.5.1.1]

Initiation and propagation of cracks in the stainless steel material are the typical effects of IGSCC. [Reference 7, Appendix L] If IGSCC of the SFP liner were left unmanaged for an extended period of time, the resulting leakage could lead to the inability to perform the intended pressure boundary function under CLB design loading conditions. [Reference 7, Appendix L]

Group 3 - (corrosion of the SFP liner) - Methods to Manage Aging

Mitigation: Because the factors affecting corrosion of the SFP liner (i.e., applied or residual stresses, SFP chemistry, and materials and methods of construction) are inherent in the structure's design and function, there are no practical methods to mitigate its effects. However, the discovery methods described below are considered adequate to manage this ARDM.

Discovery: Degradation due to IGSCC at the sensitized zones of the SFP liner would result in increasing SFP leakage and can be detected by monitoring the rate of leakage from the SFP at the "telltale" valves. [Reference 7, Appendix L] Because the SFP Cooling System provides a permanent make-up capability with suitable redundancy or back-up to prevent uncovering of fuel assemblies in the SFP, measuring and trending leakage from the SFP provides for effective aging management. [Reference 6, Section 9.4.4; Reference 7, Appendix L]

Group 3 - (corrosion of the SFP liner) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited for mitigation of corrosion of the SFP liner. [Reference 7, Appendix L]

Discovery: The Calvert Cliffs Operating Manual, NO-1-201, establishes the requirements for implementing and using Operating Instructions as approved, preplanned methods of conducting operations. [Reference 50] The CCNPP Performance Evaluation Program, NO-1-203, has been established to perform periodic operational checks and obtain readings to determine equipment performance, as determined by manufacturers' recommendations, System Engineers' recommendations, and operating needs. [Reference 51] These programs address controls for activities conducted as part of daily shift operations, and apply to operators and others who interact with them. [Reference 52]

The Performance Evaluation Program provides for determination of SFP leakage on a monthly frequency. [Reference 51, Section 5.3.B.4; Reference 53] Calvert Cliffs procedure PE 0-67-2-O-M, "#11 & #12 Spent Fuel Pools - Determine Liner Leakage," directs performance of the SFP leakage test in accordance with OI-24D, "Spent Fuel Pool Cooling - Infrequent Operations," which provides detailed instructions for leakage monitoring of the SFP Cooling System. During this test, the "telltale" valves are opened, drained, and are monitored for 24 hours with catch devices installed at the outlet of each "telltale" valve. [Reference 54, Section 6.1] If the total leakage from all "telltale" valves exceeds one gallon in a 24-hour period, an engineering evaluation of the condition is performed. [Reference 54, Section 6.1]

As part of the plant's administrative procedures hierarchy, the plant's nuclear operations procedures have numerous levels of controls and reviews, including assignment of responsibility for conducting performance evaluations as required, reviewing all the evaluations for accuracy and completeness, and analyzing data for trends, if applicable. Specific responsibilities are assigned to BGE personnel for monitoring these programs through periodic audits. The Operating Manual and the Performance Evaluation Program have also been evaluated by the NRC as part of its routine licensee assessment activities. These controls provide reasonable assurance that the associated activities will continue to be an effective method of monitoring the SFP liner for the effects of IGSCC. [References 50, 51, and 52]

Group 3 - (corrosion of the SFP liner) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of the SFP liner:

- The SFP liner serves as a pressure boundary or fission product retention barrier to protect the public health and safety in the event of any postulated DBEs and its integrity must be maintained under all CLB conditions.
- The SFP liner is constructed from stainless steel plates and exposed to a borated water environment.
- Heat-affected zones in and around the SFP liner welds may be sensitized and susceptible to IGSCC. If left unmanaged, IGSCC could eventually result in the SFP liner not being able to perform its intended function under CLB conditions
- Periodic monitoring of leakage from the SFP under the Performance Evaluation Program will identify and document the presence of leakage that may be due to IGSCC, and ensure that appropriate corrective actions are taken if total leakage exceeds acceptance criteria.

Therefore, there is reasonable assurance that the effects of aging due to IGSCC of the SFP liner will be managed in such a way that it will be capable of performing its intended function consistent with the CLB during the period of extended operation.

Group 4 - (degradation of neutron-absorbing materials) - Materials and Environment

In 1980, the Unit 1 side of the SFP was modified with the installation of high-density spent fuel storage racks. These structural components consist of a base structure supporting storage cells primarily fabricated from stainless steel. A neutron-absorbing sheet, fabricated by The Carborundum Company and consisting of a boron carbide powder in a fiberglass matrix, is sandwiched between the inner and outer walls on the four sides of each storage cell. The Unit 2 side of the SFP was similarly modified in 1983; however, a different neutron-absorbing sheet, consisting of fine particles of boron carbide in a silicon polymer matrix, was used. This neutron-absorbing material is Boraflex, which is a trademark sheet form of a proprietary material manufactured by Brand Industrial Services, Inc.

The intended function of the SFP storage racks is to provide structural/functional support for fuel assemblies by maintaining a subcritical geometry in the SFP. The neutron-absorbing sheet materials are not load-bearing structural components; however, they contribute to the intended function of the storage racks by absorbing neutrons in the SFP. Absorption of neutrons by these materials is assumed in the SFP criticality calculations. [Reference 6, Section 9.7.2.1] The SFP storage racks are immersed in the borated water contained inside the pool. [Reference 7, Appendix L]

Group 4 - (degradation of neutron-absorbing materials) - Aging Mechanism Effects

Experiments have shown that unencapsulated Carborundum sheets experience a loss of boron carbide when exposed to gamma radiation in a water environment. [Reference 55, Enclosure 3, Section 5.1.7] Embrittlement and weakening of the polymeric bond phase reduces the tenacity with which the boron carbide particles are held. After exposures at higher levels of gamma radiation, unencapsulated Carborundum sheets are susceptible to spalling and surface abrasion, which may result in loss of boron carbide material. These losses would be reflected in an observable decrease in sheet thickness and weight. [Reference 56]

Several utilities have observed significant loss of Boraflex material from sample coupons. When the Boraflex material is subjected to gamma radiation in the SFP environment, the silicon polymer matrix becomes degraded, which may result in: (a) release of the silica filler and boron carbide from the sheet; and (b) shrinkage of the polymer and development of gaps in the material. The loss of boron carbide from Boraflex is characterized by slow dissolution of the Boraflex matrix from the surface of the sheet and gradual thinning of the material. The access of water to and around the Boraflex sheets is a significant factor influencing the rate of silica dissolution from Boraflex. [Reference 57]

The use of adhesives to bond Boraflex sheets to steel in the storage cells is a significant factor leading to gap formation. Since the installation process for individual storage racks in the Unit 2 side of the SFP involved only single sheets of Boraflex material that were not fastened or permanently glued onto any surface or structure, gap formation due to Boraflex shrinkage is not expected. [Reference 58] Experimental data from industry test programs support conservative assumptions in SFP criticality analyses that encompass the gapping phenomenon within the design basis of the storage racks. [Reference 6, Section 9.7.2.1; Reference 57]

Degradation of the neutron-absorbing materials used in the SFP storage racks is plausible because they are exposed to gamma radiation and borated water in the SFP environment. A reduction in the amount of boron in the sheets (through spalling and surface abrasion of the Carborundum material, or dissolution of silica from the Boraflex material) could result in an increase in the reactivity of the SFP configuration.

Group 4 - (degradation of neutron-absorbing materials) - Methods to Manage Aging

Mitigation: The SFP storage rack designs incorporate a vented, form-fitted wrapper that minimizes water ingress and gas accumulation. Because the factors affecting degradation of the neutron-absorbing materials (i.e., exposure to borated water and gamma radiation) are inherent in the design and function of the storage racks, there are no additional methods to mitigate its effects. However, the discovery methods described below are considered adequate to manage this ARDM.

Discovery: Industry experience indicates that degradation in neutron absorption performance has not been observed in materials other than Boraflex. [Reference 59] Although predictive computer models and areal density measurement techniques are under development in the industry, practical methods to directly monitor degradation of Boraflex material in the Unit 2 SFP storage racks are not currently available for use. [Reference 60] However, degradation of either type of neutron-absorbing material can be monitored by periodic testing of sample coupons that are representative of the materials installed in the SFP storage racks. [Reference 61]

Group 4 - (degradation of neutron-absorbing materials) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited for mitigating the degradation of neutron-absorbing materials in the SFP storage racks.

Discovery: Calvert Cliffs Administrative Procedure EN-4-101, "Coordination of Testing," provides the administrative process for the use of Engineering Test Procedures (ETPs). This program was established to ensure a comprehensive and integrated approach to testing activities. These activities require identification of testing requirements, specification of required plant conditions to perform the tests, development of procedures, integration of tests into a schedule based on required plant conditions, and accomplishment of testing according to schedule. [Reference 62, Section 5.1.A]

Calvert Cliffs ETP 86-03R, "Analysis of Neutron Absorbing Material in Spent Fuel Storage Racks," was developed on the basis of vendor recommendations for detecting degradation of neutron-absorbing materials. [Reference 63, Section 3.1.D] This program is designed to permit samples of the materials used in the SFP storage racks to be periodically removed from the SFP for examination. Through specific positioning of designated sample packets, both accelerated and long-term exposure to gamma radiation and borated water is provided. The long-term sample packets are surrounded by typical fuel assemblies, while the accelerated sample packets are placed next to the freshly-discharged fuel every refueling outage. [Reference 61] The sample coupons are a conservative representation of the neutron-absorbing materials in the SFP storage racks. The sample packet holders have a small gap between the top, bottom, and side spacer bars. Additionally, the spacer bars are 0.01 inches thicker than the sample coupons. These dimensional differences actually allow ingress of water to the sample coupon material; this effect is minimized in the SFP storage racks by the wrapper encapsulating the neutron-absorbing material. [Reference 61] Each sample packet contains coupons of either Carborundum or Boraflex material. Sufficient samples are available so that the principal physical properties (i.e., sample weight for the Carborundum material, and sample hardness for the Boraflex material) can be determined as a function of exposure on a regularly scheduled basis. Visual condition is assessed on a graded scale, and the results of physical property analyses are compared to historical results. Vendor documents provide guidelines for interpreting test results. [Reference 63] Unacceptable results are documented, reported, and corrected in accordance with the CCNPP Corrective Actions Program. [Reference 62, Section 5.5.B.11]

The cumulative results of the coupon surveillance program indicate that the neutron-absorbing sheets have experienced no significant deterioration after more than 12 years of service. Evidence of erosion has been observed in sample coupons in the vicinity of inspection holes in the associated sample holder. This erosion was determined to be the result of water flow on the surface of the material. This flow is due to thermal gradients produced by the spent fuel in the racks. Since the inspection holes in the SFP storage racks themselves are located above the level of the active fuel, erosion of material in their vicinity would not result in loss of the neutron-absorption function. There is no evidence that such erosion is occurring at locations other than the immediate vicinity of the sample holder inspection holes.

As part of the plant's administrative procedures hierarchy, ETPs have numerous levels of controls and reviews, including assignment of responsibility for identifying tests and associated plant conditions, conducting tests as required, and performing independent technical review of test results. [Reference 62] Specific responsibilities are assigned to BGE personnel for monitoring these programs through periodic audits. [Reference 33] Calvert Cliffs ETPs have also been evaluated by the NRC as part of its routine licensee assessment activities. [Reference 64] Calvert Cliffs will continue using the coupon surveillance program as the primary activity for monitoring condition of the neutron-absorbing materials in the SFP storage racks. As other methods are developed and determined to be effective (i.e., industry initiatives such as predictive computer models and areal density measurement techniques), they will be considered for applicability at CCNPP. [Reference 61]

Currently, the coupon surveillance program requires removal of one long-term Carborundum sample packet and one long-term Boraflex sample packet from the SFP every four years; one accelerated sample packet of each material type is removed from the SFP every two years. [Reference 63, Attachment 1] The basis for this original timetable was a 40-year service life for the SFP storage racks; for each material type, two additional long-term and two additional accelerated sample packets were provided for contingency use. The program described above will be modified to: (a) reevaluate the adequacy of the sampling intervals in monitoring Carborundum and Boraflex condition through the period of extended operation; and (b) refine the process for scheduling sample packet removal from the SFP. The modified program will ensure that degradation of neutron-absorbing material is identified and corrected such that the SFP storage racks will be capable of performing their intended functions consistent with CLB design conditions.

Group 4 - (degradation of neutron-absorbing materials) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to degradation of Carborundum and Boraflex materials in the SFP:

- The SFP storage racks incorporate neutron-absorbing materials to maintain the required subcritical margin for fuel assemblies in the SFP environment, and their function must be maintained under all CLB conditions.
- The Carborundum material (in the Unit 1 SFP storage racks) and the Boraflex material (in the Unit 2 SFP storage racks) is exposed to a borated water environment.
- Experiments have shown that the Carborundum sheets can experience spalling and surface abrasion, which result in a loss of boron carbide, after exposures at higher levels of radiation. Industry experience indicates that the silica filler in the Boraflex material can dissolve in the SFP environment and release the boron carbide neutron absorber. If left unmanaged, degradation of these neutron-absorbing materials could eventually result in the SFP storage racks not being able to perform their intended function under CLB conditions.
- The coupon surveillance program provides for periodic monitoring of the condition of neutron-absorbing materials in the SFP. The program will be modified to reevaluate the timetable and refine the scheduling process for removal of sample packets from the SFP. The program will identify and document degradation of the Carborundum and Boraflex materials, and ensure appropriate actions are taken in a timely manner if significant loss of neutron-absorbing capability is occurring.

Therefore, there is reasonable assurance that the effects of neutron-absorbing material degradation will be managed in such a way that the SFP storage racks will be capable of performing their intended function consistent with the CLB during the period of extended operation.

3.3E.3 Conclusion

The aging management programs discussed for the Auxiliary Building and SR Diesel Generator Building Structures are listed in Table 3.3E-4. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects in such a way that the intended functions of the components of the Auxiliary Building and SR Diesel Generator Building Structures will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 3.3E-4

AGING MANAGEMENT PROGRAMS FOR THE AUXILIARY BUILDING AND SR DIESEL GENERATOR BUILDING STRUCTURES

	Program	Credited As
Existing	CCNPP Technical Procedure STP-F-592-1/2, "Penetration Fire Barrier Inspection"	Program for discovery and management of weathering effects for caulking, sealants, and expansion joints that function as fire barriers in the Auxiliary Building and adjacent rooms by visual inspection. (Group 1)
Existing	Operations Section Performance Evaluation PE 0-67-2-O-M, "#11 & #12 Spent Fuel Pools - Determine Liner Leakage," and associated Operating Instruction OI-24D, "Spent Fuel Pool Cooling - Infrequent Operations"	Program for discovery and management of IGSCC effects for the SFP liner by performing periodic leakage monitoring. (Group 3)
Modified	Structure and System Walkdowns (MN-1-319) • Specify scope and control of periodic structure performance assessments	Program for discovery and management of corrosion effects for carbon steel components in the Auxiliary Building and SR Diesel Generator Building Structures. (Group 2)
Modified	Engineering Test Procedure 86-03R, "Analysis of Neutron Absorbing Material in Spent Fuel Storage Racks" • Reevaluate timetable and refine scheduling process for sample coupon removal from SFP	Program for discovery and management of neutron-absorbing material degradation for the SFP storage racks by performing analysis of sample coupons. (Group 4)

TABLE 3.3E-4

AGING MANAGEMENT PROGRAMS FOR THE AUXILIARY BUILDING AND SR DIESEL GENERATOR BUILDING STRUCTURES

	Program	Credited As
New	Caulking and Sealant Inspection Program	New program for discovery and management of weathering effects for caulking, sealants, and expansion joints in the SR Diesel Generator Building, as well as for those in the Auxiliary Building and adjacent rooms that do not function as fire barriers. (Group 1)

3.3E.4 References

1. CCNPP IPA Methodology, Revision 1
2. CCNPP System and Structure Screening Results, Revision 5
3. BGE Drawing 61230, "Salt Water Systems Underground Ducts Plan and Sections," Revision 6
4. BGE Drawing 63874SH0004, "SR Ductbank Under West Plant Road Plan," Revision 0
5. BGE Drawing 63874SH0005, "Underground Conduit West of Turbine Building Plan," Revision 0
6. CCNPP Updated Final Safety Analysis Report, Units 1 and 2, Revision 21
7. CCNPP Aging Management Review Report, "Auxiliary Building," Revision 3
8. BGE Drawing 61988, "Auxiliary Building at 45'-0" Emergency Generator Room Piping Ducts Unit 1," Revision 16
9. BGE Drawing 63988, "Auxiliary Building at Elevation 45'-0" Solid Waste Processing Area Unit 2," Revision 13
10. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 2
11. Letter from Mr. D. G. McDonald, Jr. (NRC) to Mr. G. C. Creel (BGE) dated January 17, 1992, "Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit No. 1 (TAC No. M71241) and Unit No. 2 (TAC No. M71242)"
12. CCNPP AMR Report, "Emergency Diesel Generator System (024)," Revision 1
13. CCNPP AMR Report, "Component Supports," Revision 3
14. CCNPP Component Level Scoping Results for the Auxiliary Building, Revision 2
15. BGE Drawing 63874SH0001, "Underground Conduit West of Turbine Building Plan," Revision 3
16. BGE Drawing 63874SH0002, "Diesel Generator Project SR & SBO Manholes & Ductbank Plans, Sections & Details," Revision 2
17. BGE Drawing 63874SH0003, "Underground Conduit West of Turbine Building Plan," Revision 0
18. Electric Power Research Institute, "PWR Containment Structures License Renewal Industry Report; Revision 1," July 1994
19. Electric Power Research Institute, "Class I Structures License Renewal Industry Report; Revision 1," July 1994
20. Bechtel Specification No. 6750-C-9, "Specification for Furnishing and Delivery of Concrete - CCNPP Units 1 and 2," Revision 22
21. BGE Diesel Generator Project Civil Engineering Design Report, Revision 1
22. BGE Design Specification No. SP-702, "Site Preparation and Earthwork Construction," Revision 2

23. BGE Design Specification No. SP-700, "Materials Testing Services," Revision 6

24. Bechtel Specification No. 6750-C-4A, "Specification for Placement and Control of Compacted Fill - CCNPP Units 1 and 2," Revision 3

25. BGE Drawing 60119, "Compacted Fill Areas," Revision 0

26. Bechtel Specification No. 6750-C-11-B, "Specification for Testing of Concrete, Reinforcement and Soil - CCNPP Units 1 and 2," Revision 1

27. NRC Inspection and Enforcement Circular 81-08, "Foundation Materials," May 29, 1981

28. BGE Drawing 61993, "Auxiliary Building Roofs Over Emergency Generator at Elevation 69'-0"," Revision 2

29. Bechtel Specification No. 6750-A-10, "Specification for Furnishing, Delivery and Application of the Caulking and Sealants," Revision 1

30. Bechtel Specification No. 6750-C-10, "Specification for Forming, Placing, Finishing, and Curing Concrete," Revision 9

31. CCNPP Technical Procedure STP-F-592-1, "Penetration Fire Barrier Inspection," Revision 3

32. CCNPP Technical Procedure STP-F-592-2, "Penetration Fire Barrier Inspection," Revision 2

33. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48

34. Letter from Mr. L. T. Doerflein (NRC) to Mr. C. H. Cruse (BGE), dated May 14, 1997, "Plant Performance Review (PPR) -- Calvert Cliffs"

35. Letter from Mr. J. T. Trapp (NRC) to Mr. R. E. Denton (BGE), dated May 6, 1994, "Combined Inspection Report Nos. 50-317/94-15 and 50-318/94-15"

36. BGE Design Specification No. SP-706, "Purchase of Category 1 Structural and Miscellaneous Steel," Revision 3

37. BGE Performance Specification No. SP-707, "Erection of Category 1 Structural and Miscellaneous Steel," Revision 1

38. Bechtel Specification No. 6750-C-31, "Specification for Furnishing, Detailing, Fabricating, Painting, and Delivering Containment and Auxiliary Building Structural Steel - CCNPP Units 1 and 2," Revision 3

39. Bechtel Specification No. 6750-C-61(Q), "Technical Specification for Furnishing and Delivering Structural Steel - CCNPP Units 1 and 2," Revision 0

40. BGE Technical Requirements Document TRD-A-1000, "Coating Application Performance Standard," Revision 14

41. BGE Design Specification No. SP-717-NSR, "Shop Applied Coating," Revision 2

42. Bechtel Specification No. 6750-C-19, "Specification for Furnishing, Detailing, Fabricating, Delivering, and Erecting Structural Steel - CCNPP Units 1 and 2," Revision 3

43. Bechtel Specification No. 6750-A-24, "Specification for Painting and Special Coatings - CCNPP Units 1 and 2," Revision 12

44. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0

45. Bechtel Specification No. 6750-C-28, "Specification for Stainless Steel Liner Plate and Spent Fuel Pool Bulkhead Gate - CCNPP Units 1 and 2," Revision 6

46. BGE Drawing 61706SH0001, "Auxiliary Building Spent Fuel Pool Liner Plan and Sections Sheet 1," Revision 18

47. BGE Drawing 61707SH0002, "Auxiliary Building Spent Fuel Pool Liner Sections and Details," Revision 19

48. BGE Drawing 61708SH0003, "Auxiliary Building Spent Fuel Pool Liner Bulkhead Gates Sheet 3," Revision 14

49. BGE Drawing 61972SH0004, "Auxiliary Building Spent Fuel Pool Liner Sections and Details Sheet 4," Revision 12

50. CCNPP Administrative Procedure NO-1-201, "Calvert Cliffs Operating Manual," Revision 7

51. CCNPP Administrative Procedure NO-1-203, "Operations Section Performance Evaluations," Revision 3

52. CCNPP Administrative Procedure NO-1-100, "Conduct of Operations," Revision 9

53. CCNPP Operations Performance Evaluation Requirements Routine No. 0-67-2-O-M, "#11 & #12 Spent Fuel Pools - Determine Liner Leakage," Revision 2

54. CCNPP Operating Instructions, OI-24D, "Spent Fuel Pool Cooing - Infrequent Operations," Revision 4

55. Letter from Mr. A. E. Lundvall, Jr. (BGE) to Mr. Robert W. Reid (NRC), dated January 15, 1980, "Spent Fuel Pool Modification Supplementary Information"

56. The Carborundum Company, "Handbook of the Effects of In-Pool Exposure on Properties of Boron Carbide-Resin Shielding Materials," (undated)

57. NRC Generic Letter 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks," June 26, 1996

58. Letter from Mr. S. A. McNeil (NRC) to Mr. G. C. Creel (BGE), dated March 7, 1989, "Amendment to Increase Enrichment Limits for the Spent Fuel Storage Racks (TAC Nos. 68416 and 68417)

59. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), dated September 18, 1996, "Resolution of Spent Fuel Storage Pool Safety Issues: Issuance of Final Staff Report and Notification of Staff Plans to Perform Plant-Specific, Safety Enhancement Backfit Analyses, Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (TAC Nos. M96516 and M96517)"

60. Electric Power Research Institute, "A Synopsis of the Technology Developed to Address the Boraflex Degradation Issue," November 1997

61. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated October 24, 1996, "120-Day Response to Generic Letter 96-04, Boraflex Degradation in Spent Fuel Pool Storage Racks"

62. CCNPP Administrative Procedure EN-4-101, "Coordination of Testing," Revision 1

63. CCNPP Engineering Test Procedure 86-03R, "Analysis of Neutron Absorbing Material in Spent Fuel Storage Racks," Revision 2

64. Letter from Mr. J. C. Linville (NRC) to Mr. G. C. Creel (BGE), dated January 30, 1991, "NRC Region I Resident Inspection Report Nos. 50-317/90-34 and 50-318/90-34 (November 25, 1990 - January 12, 1991)"

4.1 Reactor Coolant System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Reactor Coolant System (RCS). The RCS was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

4.1.1. Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools that capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 4.1.1.1 presents the results of the system level scoping, 4.1.1.2 the results of the component level scoping, and 4.1.1.3 the results of scoping to determine components subject to AMR.

Representative historical operating experience pertinent to aging is included in appropriate areas, to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

4.1.1.1 System Level Scoping

This section begins with a description of the system that includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within scope for license renewal.

<u>System Description/Conceptual Boundaries</u>

The function of the RCS is to remove heat from the reactor core and internals and transfer it to the secondary (steam generating) system. The RCS of each Unit, which is entirely located within the Containment Building, consists of two heat transfer loops connected in parallel across the reactor pressure vessel (RPV). Each loop contains one steam generator (SG), two reactor coolant pumps (RCPs), connecting piping, and flow and temperature instrumentation. Other major RCS components include the pressurizer and quench tank. Coolant system pressure is maintained by the pressurizer, which is connected to one of the RCS loop hot legs. [Reference 1, Section 4.1.2] Because the RPV is such a significant component of the RCS and because several aging mechanisms are unique to it, the RPV has a separate aging management evaluation in Section 4.2 of the BGE LRA.

The basic RCS functional requirements are: [Reference 2, Section 1.1.3]

- To remove heat from the reactor core and reactor internals and transfer it to the secondary (SGs) system;
- To contain fission products released by fuel element defects and prevent the release of these fission products to the environment;
- To provide remote monitoring capability for the RCS parameters;
- To permit remote control of RCS parameters; and
- To provide required inputs to the Reactor Protective System, the Reactor Regulating System, and the Engineered Safety Features Actuation System for protection of the reactor core and RCS components.

The primary function of the RCPs is to provide forced coolant flow through the core. There are four RCPs in the RCS of each Unit, which are located in the SG (return lines) "cold legs." [Reference 1, Section 4.1.3]

During operation, the four RCPs in each Unit circulate water through the RPV where the water serves as both coolant and neutron moderator for the core. The heated water enters the two SGs in each Unit, transferring heat to the secondary (steam) system, and then returns to the RCPs to repeat the cycle. Refer to Figure 4-1 (Unit 1) and Figure 4-17 (Unit 2) of the Updated Final Safety Analysis Report (UFSAR) for a flow diagram of the RCS. [Reference 1, Section 4.1.2]

The RCS pressure is maintained by regulating the water temperature in the pressurizer where steam and water are held in thermal equilibrium. Steam is either formed by the pressurizer heaters or condensed by the pressurizer spray to limit the pressure variations caused by contraction or expansion of the reactor coolant. The pressurizer is located with its base at a higher elevation than the RCS loop piping. [Reference 1, Section 4.1.2] A number of pressurizer heaters are operated continuously to offset the heat losses and the continuous minimum spray, thereby maintaining the steam and water in thermal equilibrium at the saturation temperature corresponding to the desired system pressure. [Reference 1, Section 4.1.3]

Overpressure protection is provided by two power-operated relief valves (PORVs) and two spring-loaded safety valves connected to the top of the pressurizer. Steam discharged from the valves is cooled and condensed by water in the quench tank. The RCS vent lines from the RPV and the pressurizer also discharge to the quench tank. In the unlikely event that the discharge exceeds the capacity of the quench tank, the tank is relieved to the containment via the quench tank rupture disc. The quench tank is located at a level lower than the pressurizer. This ensures that any PORV or pressurizer safety valve leakage from the pressurizer, or any discharge from these valves, drains to the quench tank. [Reference 1, Section 4.1.2]

The Nuclear Steam Supply System (NSSS) utilizes two SGs to transfer the heat generated in the RCS to the secondary system. The SG shell is constructed of carbon steel. Manways and handholes are provided for easy access to the SG internals. [Reference 1, Section 4.1.3]

The SG is a vertical U-tube heat exchanger. The SG operates with the reactor coolant in the tube side and the secondary fluid in the shell side. Reactor coolant enters the SG through the inlet nozzle, flows through 3/4" outside diameter U-tubes, and leaves through two outlet nozzles. Vertical partition plates in the lower head separate the inlet and outlet plenums. The plenums are stainless steel clad, while the primary side of the tube sheet is nickel-chromium-iron (Ni-Cr-Fe) clad. The vertical U-tubes are Ni-Cr-Fe alloy. The tube-to-tube sheet joint is welded on the primary side. Tubes that have degraded may be repaired using tube sleeves or removed from service by either a welded or a mechanical-type tube plug. [Reference 1, Section 4.1.3]

Feedwater enters the SG through the feedwater nozzle where it is distributed via a feedwater distribution ring. Water exits the ring through apertures in the top fitted with J-tubes, then flows into the downcomer. The downcomer is an annular passage formed by the inner surface of the SG shell and the cylindrical shell wrapper that encloses the vertical U-tubes. At the bottom of the downcomer, the secondary water is directed upward past the vertical U-tubes where heat transfer from the primary side produces a water-steam mixture. [Reference 1, Section 4.1.3.2]

Constant RCS makeup and letdown is handled by the Chemical and Volume Control System (CVCS). An inlet nozzle on each of the four RPV inlet pipes allows injection of borated water into the RPV from the CVCS and from Safety Injection System in the event emergency core cooling is needed. During a normal plant shutdown, these nozzles are also used to supply shutdown cooling flow from the low pressure safety injection pumps. An outlet nozzle on one RPV outlet pipe is used to remove shutdown cooling flow. [Reference 1, Section 4.1.2]

Drains from the RCS piping to the Radioactive Waste Processing System are provided for draining the RCS for maintenance operations. A connection is also provided on the quench tank for draining it to the Radioactive Waste Processing System following a relief-valve or safety-valve discharge. [Reference 1, Section 4.1.2]

The RCS piping consists of two loops that connect the SGs to the reactor vessel. Each loop consists of 42-inch inside diameter "hot leg" piping connecting the reactor vessel outlets to the SG inlets, and 30-inch inside diameter piping connecting the SG outlets to the RCPs and the coolant pumps to the reactor vessel inlet nozzles. A surge line connects one loop hot leg to the pressurizer. [Reference 1, Section 4.1.2]

Vents were added to the RPV head and to the pressurizer head in response to the Three Mile Island lessons learned report, "Clarification of TMI Action Plan Requirements," NUREG 0737, Item II.B.1. These vents are intended to provide a means of releasing non-condensable gases from the RCS during natural circulation. The pressurizer vent line valves are used as a backup to main and auxiliary spray to depressurize the RCS during a SG tube rupture. The original design of CCNPP allowed venting of the RCS only during cold shutdown. The vent modifications provide electrically-operated solenoid valves, powered from emergency electrical busses, that are operated from the Control Room. The RPV and the pressurizer each have two of these valves in series, which fail closed (power-to-open). The reactor vessel vent line valves are installed in previously existing lines; the pressurizer vent line valves are installed in a line that was added as an additional branch off the pressurizer vapor sample line. The two vent lines join to a common line that leads to the quench tank. The common line contains a temperature element and alarm that is used for valve seat leak detection and flow indication. [Reference 1, Section 4.1.3]

The components covered by this evaluation include the RCPs and their motors, RCS piping, pressurizer, pressurizer heaters, PORVs and safety valves, SGs, quench tank, and associated instruments and controls. The SG boundaries are set at the ends of the nozzles' safe-ends connecting the SG to other components or systems. The nozzles include main feedwater, auxiliary feedwater, main steam, RCS inlet and outlet, instrumentation, and any integral attachments. [Reference 2, Section 1.1.2]

The boundary between the RPV and RCS main coolant piping excludes the RPV nozzles, which are evaluated with the RPV and Control Element Drive Mechanisms (CEDMs)/Electrical System in Section 4.2 of the BGE LRA. [Reference 2, Section 1.1.2]

In addition, the following piping, supports, instrumentation and controls, and valves are covered or excluded in this evaluation: [Reference 2, Section 1.1.2]

Piping:

- Small tubing and piping that is field run (i.e., instrumentation tubing) and does not have component designators is not evaluated in this report;
- PORV and safety valve discharge piping is included up to but not including the connecting nozzles on the quench tank;
- Vents, drains, and other similar attached lines are included out to the second valve from the RCS; and
- Safety injection and similar lines from the interconnecting systems are included out to the first valve from the RCS.

Supports and hangers for piping and components that are not reviewed in this evaluation are evaluated in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA.

Instrumentation and Controls covered by this evaluation are: [Reference 2, Section 1.1.2]

- All remote and local instrumentation associated with the RCS loops, the pressurizer, and the RCPs. Steam generator secondary side instrumentation is not covered in this evaluation;
- Incore neutron detectors and incore (core exit) temperature monitors;
- Instrumentation scope includes transmitters, signal processing, equipment, Control Room displays, and other applicable readouts, but does not include cabling. Cabling is evaluated in the Cables Commodity Evaluation in Section 6.1 of the BGE LRA;
- Automatic and manual controls for pressurizer heaters, pressurizer spray, RCPs, and the PORV and its isolation valves are evaluated; and
- Power supply components for the RCPs and heaters are included up to the power supply breaker.

The valves covered by this review include: [Reference 2, Section 1.1.2]

- Valves associated with the pressurizer spray (including Instrument Air System supply valves to the pressurizer spray control valves);
- Pressurizer Code safety valves;
- PORV and associated motor operated block valves;

- All normally closed RCS pressure boundary valves in vent and drain lines (this extends to the second valve from the RCS in each line); and
- Instrument valves for the RCS instrumentation (e.g., pressurizer level transmitter instrument root valves).

In addition, a few valves in associated systems are included; these are: [Reference 2, Section 1.1.2]

- Two manual valves in the CVCS letdown line;
- Check valves in the CVCS RCP seal bleedoff lines;
- Two check valves in the relief piping from the RCS drain tank heat exchanger;
- The air system valves noted above; and
- RCP lube oil reservoir level transmitter root valves.

The RCP and motors and their oil lift system are included in this evaluation. The RCP and motor cooling subcomponents are included in this evaluation out to the connection with the Component Cooling (CC) System. [Reference 2, Section 1.1.2] Included in this evaluation are the SG and pressurizer supports. Component supports, cables, instrument lines, and instruments not identified as RCS components in the RCS scoping results are generically included in the Component Supports Commodity, Cables Commodity, Instrument Lines Commodity and Fire Protection AMRs. [Reference 2, Section 3.2]

System Operating Experience

The following are RCS operating experiences related to aging mechanisms with the potential for affecting the intended functions of the system components.

RCP Events

RCP Suction Deflector Failures

In 1988 and 1996, failures of RCP suction deflector bolting at CCNPP occurred and bolt fragments were assumed to be lodged in the RPV on the vessel cladding and near the downcomer. Refer to the RPV/CEDMs and Electrical System evaluation in Section 4.2 of the BGE LRA for further discussion of this event. [References 3 and 4]

RCP Leakage

On several occasions, CCNPP has shut down due to RCS leakage associated with the RCPs. These occurred primarily between 1978 and 1985, and resulted from minor leakage in RCP sensing, instrument, and controlled leakoff lines. These small RCP lines were leaking at weld locations as the result of vibratory fatigue. Corrective actions have included weld repair and replacement of welded pipe with new continuous sections of pipe for leakoff lines. In some instances the pipe supports were modified to reduce the effects of vibration. Braided hose jumpers were used with sensing and instrument lines. For piping associated with the RCP seal leakoff lines, CCNPP has implemented a vibration monitoring and reduction program, minimized vibration through continued RCP balancing, and replaced/relocated existing pipe flanges. [References 5 through 11]

The original Byron Jackson seals have been replaced with improved seals. The new seals are designed in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, 1983 Edition with Summer 1983 Addenda, and manufactured by Sulzer Bingham Pumps. [Reference 1, Section 4.1]

RCP Thermal Barrier Housing Cracks

Baltimore Gas and Electric Company has determined that NRC Information Notice 97-31, "Failures of Reactor Coolant Pump Thermal Barriers and Check Valves in Foreign Plants," is applicable to CCNPP, since there has been evidence of cracking in the RCP thermal barrier housings. Calvert Cliffs found shallow surface cracking on the 22B RCP thermal barrier housing in 1987. A safety analysis addressed the consequences of this cracking and the potential for overpressurizing the Component Cooling (CC) System. The analysis found that the CC System would not be subjected to overpressurization since there are six CC relief valves with adequate capacity inside the Containment Building. Another analysis by the pump vendor found that any cracks would be self-arresting and would go no deeper. This analysis was partially validated by CCNPP when No. 11B RCP cover was tested in the fall of 1996. The inspection found shallow surface cracks within a small area of oxide that were not evident after the oxide area was cleaned. The cover of No. 21A RCP was also inspected in June 1997, with no cracking found. The potential for thermal stress cracking in the RCPs has also been addressed by adding inspection requirements to the RCP overhaul procedures. Baltimore Gas and Electric Company has concluded that these analyses, tests, and inspection requirements adequately address the concerns of Information Notice 97-31.

Pressurizer Events

Calvert Cliffs has experienced RCS pressure boundary leakage of Alloy 600 components. During the 1989 Unit 2 refueling outage, CCNPP personnel discovered evidence of RCS leakage from approximately 20 of 120 pressurizer heater sleeves. Unit 1 was shut down from 100% power to allow inspection of the pressurizer. No signs or evidence of leakage was found on the Unit 1 pressurizer heater penetrations or pressure/level instrumentation penetrations. Both units remained shut down until the cause was understood.

The cracks were of an axial nature and eventually determined to be not safety significant. [Reference 12] Upon further evaluation it was determined that the cause of the leakage was primary water stress corrosion cracking (PWSCC). Primary water SCC is stress corrosion cracking (SCC) that occurs in susceptible materials exposed to the primary water environment of the RCS. [Reference 13] Calvert Cliffs has a total of 244 Alloy 600 penetrations in the Unit 1 RCS, and 126 remaining in Unit 2 (120 pressurizer heater sleeves were replaced with Alloy 690 in 1989-1990). In addition, a pressurizer vapor space instrument nozzle was found leaking in May 1989, which led to the replacement of all four of the Unit 2 pressurizer vapor space nozzles with Alloy 690. During the Unit 1 1994 refueling outage, two other heater sleeves were found leaking and were plugged. The remaining 188 heater sleeves were nickel-plated, as a preventive method to halt PWSCC. These events contributed to the development and evaluation of the CCNPP Alloy 600 Program Plan, which manages PWSCC in the RCS. [Reference 14, Sections 1, 2, 3, 18, 19]

SG Events

The CCNPP SGs have been repeatedly and extensively examined with different non-destructive examinations techniques. These non-destructive examination techniques include eddy current testing (bobbin coil examinations, and the Motorized Rotating Pancake Coil and Plus Point system). These examinations found some SG tubes that have degraded due to intergranular stress corrosion cracking (IGSCC), which is the result of material stress, environment, and age. The results of these SG inspection reports are submitted to the NRC. [References 15 and 16] Another degradation mechanism includes denting of the SG tubes. Denting has occurred on numerous tubes and may cause them to eventually crack. Currently, all tubes with cracks are repaired upon detection of the crack. [Reference 17]

To minimize denting, Calvert Cliffs has removed major copper sources from the feedwater and condensate systems and maintained a low oxygen level with secondary chemistry control. [Reference 17] There has also been circumferential cracking of the SG tubes at the hot leg tube sheet expansion transition. All tubes with circumferential cracking are removed from service. The aging mechanism was determined to be IGSCC originating on the secondary side (outer diameter) of the tubes. Calvert Cliffs maintains elevated pH chemistry on the SG secondary side to limit iron transport to the SGs and, therefore, the deposits in the SG. Steam generator deposits create local chemistry conditions conducive to intergranular attack (IGA)/IGSCC. [References 15 and 16]

The primary degradation mechanism of both Unit 1 and 2 SGs is outside diameter initiated IGA/IGSCC. Unit 1 degradation is primarily located in the hot leg upper tube bundle freespan and the hot leg tubesheet transition zone. Unit 2 degradation is primarily located at the hot leg tubesheet transition zone. Baltimore Gas and Electric has pulled several tubes containing stress corrosion cracks from these zones and burst tested them to near virgin tube pressures to show significant margin to structural integrity limits. Baltimore Gas and Electric has also performed in situ pressure tests on degraded tubes to demonstrate adequate structural integrity consistent with the requirements of Regulatory Guide 1.121.

Baltimore Gas and Electric Company is aware of SG flow-assisted corrosion at the San Onofre Nuclear Generating Station and will monitor industry activity related to this aging mechanism. Calvert Cliffs will respond to any NRC generic communications on this matter as part of the CLB. An evaluation of flow-assisted corrosion for CCNPP SGs will be incorporated into annual updates of the BGE LRA.

Other RCS Events

RCS Resin Intrusion

Calvert Cliffs Unit 1 had a resin intrusion in March 1989, and Unit 2 suffered a resin intrusion in January 1983, due to a failed outlet retention element of the ion exchanger in the purification system. The effect on the RPVs was evaluated at the time of the intrusions, as discussed in Section 4.2 of the BGE LRA, and found to be acceptable. Resin intrusions are a potential issue since resin decomposition products (sulfates) may contribute to cracking of sensitized Alloy 600, and the Unit 1 resin intrusion event caused elevated sulfate levels in the RCS. The Unit was shut down to restore chemistry. The sulfate concentration in the RCS was evaluated by Combustion Engineering (CE) and BGE, and the potential increase for PWSCC or IGSCC was determined to be insignificant. [References 18 and 19]

Boric Acid Corrosion

There have been several instances of external corrosion on RCS components due to boric acid leakage. In 1981, CCNPP Unit 2 experienced boric acid wastage on the RCS cold leg near the suction pipe to an RCP. This wastage (determined to be general corrosion) penetrated to a maximum depth of 1/8 inch (nominal pipe wall thickness 3.6 inches) and extended about 20 percent around the circumference of the pipe.

Inservice examination also revealed corrosion damage on the closure studs of two of the four RCPs. [Reference 20] A modification was made to install a stainless steel skirt on the RCPs to prevent any potential borated water leakage from dripping onto the RCS cold leg piping.

RCS Chemistry

An incident related to RCS plant chemistry occurred in October 1979 when an abnormally high ingress of oxygen occurred. This oxygen ingress resulted in an increase of corrosion products in the RCS and eventually to buildup of corrosion products on core surfaces. This corrosion product buildup resulted in axial power imbalance (the corrosion products were a neutron absorber) and a slight increase in the differential pressure drop across the core. This power imbalance led to a 50% power reduction. The source of the oxygen ingress was found and terminated. Calvert Cliffs treated the RCS with hydrogen peroxide during a cold shutdown of the Unit and significant corrosion product releases were observed. Upon return to power, core differential pressure and axial power distribution returned to normal. No fuel failures were observed because of this event. [Reference 21]

RPV Head Closure Seal Leakage Detection Line

Stress corrosion cracking was discovered in 1994 during a metallurgical examination of the Unit 2 RPV head closure seal leakage detector instrument line. Leakage from the line was noted during a routine post-trip containment inspection. The pipe was replaced and an examination confirmed that the failure mechanism was transgranular SCC (TGSCC) of stainless steel. Baltimore Gas and Electric Company concluded that the most likely initiator of the TGSCC was an ever increasing concentration of contaminants in the vicinity of the cracking due to repeated boil off of the liquid left in the line at the end of each refueling, eventually reaching levels high enough to cause TGSCC. [Reference 22] Even though the flawed portion of the line on Unit 2 was replaced during the January 1994 shutdown, BGE replaced the entire pipe during the 1994 refueling outage. Baltimore Gas and Electric Company also conducted non-destructive examination of the Unit 1 RPV head closure seal leakage detector instrument line and discovered flaw indications. As a result, the entire line was replaced and rerouted to an alternate flange tap. To prevent recurrence of TGSCC in the RPV head closure seal leakage monitor lines, BGE currently intends to drain the line after each refueling outage to eliminate liquid/vapor interface in high temperature sections of the line, and remove contaminants that create an environment conducive to TGSCC. [References 22 and 23]

In summary, these RCS events demonstrate that CCNPP has and will continue to address and perform corrective actions as required so that the RCS components are capable of performing their intended function under all current licensing basis (CLB) design loading conditions during the period of extended operation.

<u>System Interfaces</u>

The major RCS interfaces are with the CVCS, Safety Injection System, Reactor Protective System, Reactor Regulating System, Engineered Safety Features Actuation System, NSSS sampling, and the RPVs/CEDMs. Other interfaces include CC, Main Steam, Feedwater, and Auxiliary Feedwater Systems. A simplified flow diagram of the RCS and its interfacing systems and components is provided in Figure 4.1-1. [Reference 1, Figures 4-1, 4-17, Reference 2, Section 1.1.2, Reference 24]

Those systems or systems' components interfacing with the RCS that are within the scope of license renewal are noted with an asterisk (*) in Figure 4.1-1. Where a system, component, commodity, or structure interface is in scope for license renewal, it will be addressed by the respective section of this application for that system, component, commodity, or structure.

APPENDIX A - TECHNICAL INFORMATION
4.1 - REACTOR COOLANT SYSTEM

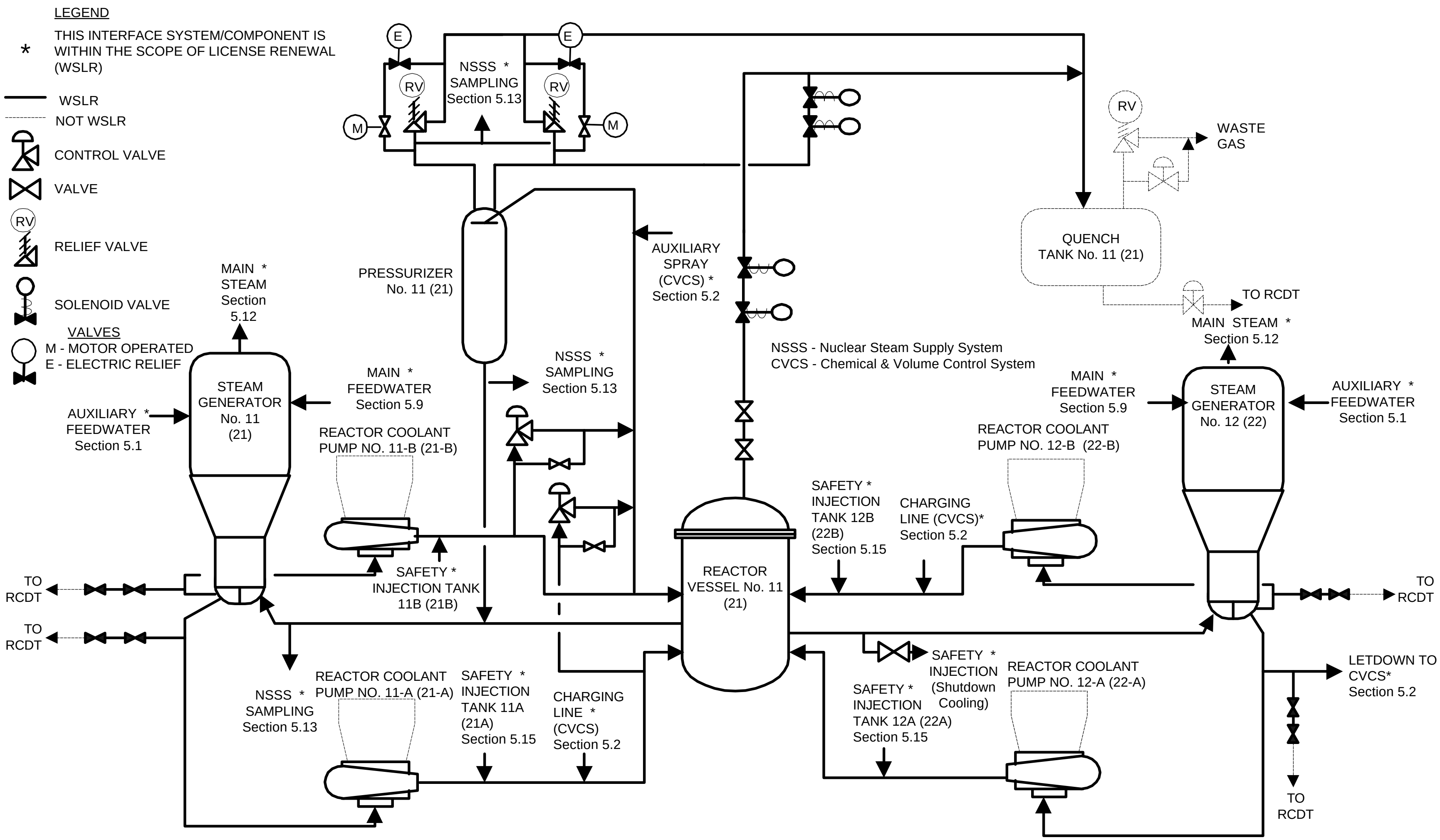

FIG. 4.1-1
UNIT No. 1 REACTOR COOLANT SYSTEM
SIMPLIFIED DIAGRAM
(INFORMATION ONLY)

System Scoping Results

The RCS components are within scope for license renewal based on 10 CFR 54.4(a). In accordance with Section 4.1.1 of the CCNPP IPA Methodology, a detailed list of system intended functions was determined based on the requirements of 10 CFR 54.4(a)(1) and (2): [Reference 25, Table 1]

- To provide manual control of RCS pressure and pressurizer level via charging pumps during design bases events;
- To control RCS pressure by regulating water temperature in the pressurizer;
- To provide indication of degrees of subcooling during design basis events;
- To provide wide range loop temperature signals via resistance temperature detector circuits;
- To provide thermal margin/low pressure signals to the Reactor Protective System for thermal margin/low pressure trip;
- To provide coastdown flow on interruption of power to the RCPs;
- To vent the RCS when natural circulation flow has been disrupted or blocked by accumulation of non-condensable gases;
- To provide differential pressure signals to the Reactor Protective System for low flow trip;
- To provide valve operation logic signals to support Safety Injection System functions;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas for five process fluids, RCS primary side, Feedwater/Main Steam secondary side, CC System, and RCP lube oil);
- To provide containment isolation of the RCS during a loss-of-coolant accident;
- To provide reactor core decay heat removal via natural circulation. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);
- To provide indication of natural circulation flow via core exit thermocouples. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);
- To provide reactor vessel coolant inventory level indication. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);
- To provide protection from overpressure in the RCS. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);

The following RCS intended functions were determined based on the requirements of 10 CFR 54.4(a)(3): [Reference 25, Table 1, TPR Section]

- For station blackout (§50.63) - To detect leakage from the primary system following loss of AC power;
- For station blackout (§50.63) and fire protection (§50.48) - To provide RCS isolation to maintain inventory following loss of AC power;

- For post-accident monitoring - To provide information used to assess the environs and plant conditions during and following an accident;
- For environmental qualification (§50.49) - To maintain functionality of electrical components as addressed by the Environmental Qualification Program;
- For fire protection (§50.48) - To provide lube oil collection for RCP motors sized to accommodate the largest potential oil leak;
- For fire protection (§50.48) - To provide monitoring of essential parameters for ensuring safe shutdown in the event of a postulated severe fire;
- For fire protection (§50.48) - To provide RCS heat removal by realignment and operation of the shutdown cooling flowpath;
- For fire protection (§50.48) - To control RCS pressure by regulating pressurizer water temperature during shutdown in the event of a postulated severe fire.

The design parameters for each of the major RCS components are given in Section 4.1.3 of the CCNPP UFSAR. The RCS is designated as a Category I system for seismic design and a Class 1 system for the criteria of load combinations and stress that are presented in Tables 4-6, 4-7, and 4-8 of CCNPP UFSAR Section 4.1.3. The regulations listed in 10 CFR 54.4(a)(3) do not necessarily require nuclear safety grade components in order to respond to the requirements of the regulations. However, the components of the RCS that have intended functions listed above associated with these regulations are safety-related, Seismic Class 1, and are subject to the applicable loading conditions identified in UFSAR Section 4.1.3, Table 4-8.

4.1.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the RCS that is within the scope of license renewal includes piping, components (e.g., heat exchangers, pressure vessels, pumps, valves, tanks, etc.), and instrumentation that are relied on for mitigation of design basis events, station blackout, post-accident monitoring, environmental qualification, and fire protection.

A total of 63 device types within the RCS equipment types were designated as within the scope of license renewal based on these intended functions. These device types are listed in Table 4.1-1. [Reference 25]

Several components are common to many plant systems and perform the same passive functions regardless of system. These components include the following:

- Structural supports for piping, cables and components;
- Electrical cabling; and
- Process and instrument tubing, instrument tubing manual valves, and tubing supports.

TABLE 4.1-1
RCS DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Code	Device Description	Device Code	Device Description
-CC	Pipe Line with Piping Code of "CC"	PC	Pressure Controller
-GC	Pipe Line with Piping Code of "GC"	PDT	Differential Pressure Transmitter
-HB	Pipe Line with Piping Code of "HB"	PI	Pressure Indicator
-HC	Pipe Line with Piping Code of "HC"	PIA	Pressure Indicator, Alarm
AE	Analyzer Element	PIC	Pressure Indicator Controller
AI	Analyzer Indicator	PNL	Panel
BKR	Circuit Breaker	PR	Pressure Recorder
CKV	Check Valve	PT	Pressure Transmitter
COIL	Electric Coil	PUMP	Pump
CV	Control Valve	PY	Pressure Relay
EI	Voltage/Current Device	PZV	Pressure Vessel
ERV	Electronically-Operated Relief Valve	RI	Radiation Indicator
FU	Fuse	RV	Relief Valve
HS	Hand Switch	RY	Relay
HV	Hand Valve	SV	Solenoid Valve
HX	Heat Exchanger	TE	Temperature Element
I/I	Current/Current Device	TI	Temperature Indicator
II	Ammeter	TK	Tank
JL	Power Lamp Indicator	TP	Temperature Test Point
LC	Level Controller	TR	Temperature Recorder
LG	Level Gauge	TT	Temperature Transmitter
LI	Level Indicator	TY	Temperature Relay
LIC	Level Indicating Controller	U	Heater
LR	Level Relay	VE	Vibration Element
LT	Level Transmitter	VI	Vibration Indicator
LY	Level Relay	VIA	Vibration Indicating Alarm
M/P	Microprocessor	VT	Vibration Transmitter
MD	125/250 VDC Motor	XL	Miscellaneous
MH	13kV Motor/Machine	YX	Power Supply
MOV	Motor-Operated Valve	ZL	Position Indicating Lamp
NB	480 V Local Control Station	ZS	Position Switch
PA	Pressure Alarm		

4.1.1.3 Components Subject to AMR

This section describes the components of the RCS that are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following RCS functions were determined to be passive. [Reference 25, Attachments 1]

- To maintain the pressure boundary of the system (liquid and/or gas for five process fluids, RCS primary side, Feedwater/Main Steam secondary side, CC System, and RCP lube oil);
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To provide containment isolation of the RCS during a loss-of-coolant accident.

Device Types Subject to AMR

The components of the RCS and their supports were reviewed and those that have the passive intended functions were identified. Of the 63 device types identified within scope for license renewal: [Reference 2, Table 3-2]

- The RPVs and their supports are evaluated for the effects of aging in the RPVs and CEDMs/Electrical System Evaluation in Section 4.2 of BGE's LRA. [The device type PZV evaluated is the pressurizer.]
- One device type, the TE pressure wells, were considered to be part of the pipe and were evaluated with the piping.
- One device type, TPs, or Reactor Vessel Level Monitoring System probes, are evaluated for the effects of aging in the RPV and CEDMs/Electrical System Evaluation in Section 4.2 of BGE's LRA.
- Five device types, LT, PT, PI, PIA, and PDT, are evaluated in the Instrument Lines Commodity Evaluation in Section 6.4 of BGE's LRA.
- One device type, PNL, is evaluated in the Electrical Commodities Evaluation in Section 6.2 of BGE's LRA.
- Some of the LT and PT device types are subject to replacement (environmental qualification).
- Thirty-nine device types; AE, AI, BKR, COIL, EI, FU, HS, I/I, II, JL, LC, LI, LIC, LR, LY, M/P, MD, MH, NB, PA, PC, PIC, PR, PY, RI, RY, TI, TR, TT, TY, U, VE, VI, VIA, VT, XL, YX, ZL, and ZS are only associated with active functions.

The 16 remaining device types have passive intended functions and are long-lived. The device types are listed in Table 4.1-2. They are subject to AMR (RCS), and are the subject of the remainder of this report.

Several components in the RCS are common to many plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 2, Section 1.1.3]

- Those structural supports for piping, cables, components in the RCS that are subjected to AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA, except for the SG supports and pressurizer support skirts that are evaluated in this section.
- Electrical cabling for components in the RCS that are subject to AMR are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the RCS passive intended function, "To maintain electrical continuity and/or provide protection of the electrical system."
- Instrument tubing and piping, and the associated supports, instrument valves, and fittings for components in the RCS that are subject to AMR, and the pressure boundaries of the instrument themselves, are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

As a result of the evaluations described above, the only passive intended function associated with the RCS is the following:

- To maintain the pressure boundary of the system (liquid and/or gas for five process fluids, RCS primary side, Feedwater/Main Steam secondary side, CC System, and RCP lube oil); and
- To provide containment isolation of the RCS during a loss-of-coolant accident.

The containment isolation function requires maintaining pressure boundary of components that are not contiguous with the RCS safety-related pressure boundary. The two pressure boundary hand valves for sampling the pressurizer quench tank form a portion of the containment isolation function. The remaining sampling components are located in the NSSS Sampling Evaluation in Section 5.13 of the BGE LRA. [Reference 25, Attachments 1]

TABLE 4.1-2

RCS DEVICE TYPES REQUIRING AMR

Piping (-CC)
Piping (-GC)
Piping (-HB)
Piping (-HC)
Check Valve (CKV)
Control Valve (CV)
Electronically-Operated Relief Valve (ERV)
Hand Valve (HV)
Heat Exchanger (HX)
Level Gauge (LG)
Motor-Operated Valve (MOV)
Pump (PUMP)
Pressure Vessel (PZV)
Relief Valve (RV)
Solenoid Valve (SV)
Tank (TK)

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period are not subject to AMR.

4.1.2 Aging Management

The potential ARDMs for the RCS components are listed in Table 4.1-3. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate column. The device types listed in Table 4.1-3 are those previously identified in Table 4.1-2 as passive and long-lived. The device types not included in Table 4.1-3 were previously dispositioned with the CCNPP IPA Methodology as performing an active function, are replaced and/or addressed in commodity evaluations. For efficiency in presenting the results of these evaluations in this report, the components are grouped together based on similar ARDMs. [Reference 2, Section 4.4]

The following discussions present information on plausible ARDMs. The discussions are grouped by ARDMs and address the materials and environment pertinent to the ARDM, the aging effects for each plausible ARDM, the device types that are affected by each, the methods to manage aging, the aging management program(s), and the aging management demonstration. The groups addressed are:

Group 1 - Denting
Group 2 - Wear
Group 3 - Erosion/Erosion Corrosion
Group 4 - Fatigue
Group 5 - Galvanic /General Corrosion and Pitting
Group 6 - IGA
Group 7 - SCC/IGSCC/PWSCC
Group 8 - Thermal Embrittlement

TABLE 4.1-3
POTENTIAL AND PLAUSIBLE ARDMs FOR THE RCS

	Device Type																
Potential ARDM Name	-CC	-GC	-HB	-HC	CKV	CV	ERV	HV	HX S/G	HX	LG	MOV	PUMP	PZV	RV	SV	TK
Cavitation Erosion																	
Contamination Sedimentation Fouling																	
Corrosion Fatigue																	
Creep/Shrinkage																	
Crevice Corrosion																	
Denting									✓(1)								
Dynamic Loading																	
Electrical Stressors																	
Erosion													✓(3)				
Erosion Corrosion									✓(3)								
Fatigue	✓(4)	✓(4)			✓(4)	✓(4)	✓(4)		✓(4)			✓(4)	✓(4)	✓(4)	✓(4)		
Galvanic Corrosion								✓(5)					✓(5)				
General Corrosion	✓(5)	✓(5)			✓(5)		✓(5)		✓(5)			✓(5)	✓(5)	✓(5)	✓(5)		
Hydrogen Damage																	
IGA										✓(6)							
Intergranular Corrosion																	
Irradiation Embrittlement																	
Microbiologically-Influenced Corrosion																	
Neutron Embrittlement																	
Oxidation																	
Particulate Wear Erosion																	
Pitting									✓(5)								
Radiation Damage																	
Saline Water Attack																	
Selective Leaching																	
SCC	✓(7)	✓(7)			✓(7)	✓(7)	✓(7)	✓(7)	✓(7)			✓(7)		✓(7)	✓(7)		
IGSCC	✓(7)	✓(7)												✓(7)			
PWSCC									✓(7)					✓(7)			
Stress Relaxation																	
Thermal Damage																	
Thermal Embrittlement	✓(8)												✓(8)	✓(8)			
Wear	✓(2)	✓(2)		✓(2)		✓(2)	✓(2)	✓(2)	✓(2)	✓(2)		✓(2)	✓(2)	✓(2)			

✓ indicates plausible ARDM determination
(#) Indicates the group in which this ARDM is evaluated

Group 1 (denting) - Materials and Environment

Table 4.1-3 shows that denting is plausible for the SG HX tubes, which are fabricated from Alloy 600. [Reference 2, Attachments 4, 5, 6, HX-01] Denting only occurs on the secondary side (on the SG HX tube exterior surfaces). The secondary side of these HX tubes are exposed to the internal environment of the SGs.

The internal SG secondary side environment during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapters 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

Group 1 (denting) - Aging Mechanism Effects

Denting refers to mechanical deformation of the SG tubes at support plates due to accelerated corrosion of the support plate structures. The corrosion products have a lower density than the base metal and tend to fill the space between the supports and the tubes. When the spaces are filled, additional corrosion causes the tubes to deform. Tube denting has been observed in CE SGs. [Reference 2, Attachments 7, HX - SG]

Therefore, denting was determined to be plausible for the SG HX tubes for which aging effects must be managed during the period of extended operation.

Group 1 (denting) - Methods to Manage Aging

Mitigation: Design features, such as the proper design and material selection of the RCS device types susceptible to this ARDM, can mitigate the effects of denting. Maintaining proper chemistry control on the secondary side of the SG could aid in mitigating the effects of denting.

Discovery: Denting of the SG HX tubes can be discovered by remote examination during plant refueling outages. Indications of denting identified during examinations of RCS components during refueling outages can be recorded and evaluated for potential damage.

Group 1 (denting) - Aging Management Program(s)

Mitigation: There are no programs to mitigate the effects of denting other than the proper design and material selection for the intended application. No credit is taken for secondary chemistry control in the mitigation of denting.

Discovery: The CCNPP Surveillance Test Procedures STP-M-574-1/2, "Eddy Current Examination of CCNPP 1/2 SGs," are credited for discovering denting in SG HX tubes. The procedure directs the user as to the sample size for tube inspection, inspection process, evaluation, and determination of tube status. The evaluation of SG HX tubes is accomplished with this procedure, Electric Power Research Institute (EPRI)/industry guidelines, and CCNPP Technical Specifications. The SG HX tubes are ranked in categories of degradation according to the CCNPP Technical Specifications. The Technical Specifications have three categories for inspection results based on the percentage of tubes that are classified as degraded and defective. The eddy current acceptance criteria for SG HX tubes are:

- Imperfection - means an exception to the dimensions, finish, or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.
- Degraded tube - means a tube containing imperfections $\geq$ 20% of the nominal wall thickness caused by degradation.
- Defect - means an imperfection of such severity that it exceeds the plugging or repair limit. A tube containing a defect is defective. Any tube that does not permit the passage of the eddy-current inspection probe shall be deemed a defective tube.
- Plugging or repair limit - means the imperfection depth at or beyond which the tube shall be removed from service by plugging, or repaired by sleeving in the affected area because it may become unserviceable prior to the next inspection. The plugging or repair limit imperfection depths are specified as 40% of original nominal tube wall thickness or 40% of Westinghouse laser-welded sleeve wall thickness.

An Issue Report (IR) is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure before the next inspection. The inspection frequency for SG HX tubes is determined by the CCNPP Technical Specifications. [References 27 and 28] For purposes of SG tubing, "susceptible to failure" means active degradation has been identified through inspection and the tube is susceptible to not satisfying structural integrity limits prior to the next refueling outage (or next inspection).

The Unit 1 and 2 SG tubes are inspected during each unit's refueling outage. Inspections are based on EPRI guidance, applicable industry experience, Technical Specifications and site-specific SG degradation characteristics. Consistent with this, BGE is currently an active participant on committees sponsored by EPRI, CE Owners Group, and the Nuclear Energy Institute focusing on preservation of SG structural integrity.

Group 1 (denting) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the SG HX tubes that are susceptible to denting:

- The SG HX tubes are a pressure-retaining boundary for the RCS, so their integrity must be maintained under CLB design conditions.
- Denting is plausible for the SG HX tubes and could result in the deformation of component material, leading to the loss of the pressure-retaining boundary function.
- The CCNPP Technical Procedures STP-M-574-1/2 are credited for discovering denting of the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.

Therefore, there is reasonable assurance that the effects of denting will be managed in order to maintain the pressure boundary integrity for the Group 1 components listed above under all design conditions required by the CLB during the period of extended operation.

Group 2 (wear) - Materials and Environment

Table 4.1-3 shows that wear is plausible for some of the RCS components. These susceptible RCS components and their material characteristics are: [Reference 2, Attachments 4, 5, 6, -CC-02/03/04, -GC-01/02/03/04/05/06, CV-01, ERV-01,-HC-01, HV-01/03/04, HX-01/02, PUMP-01, PZV-01, MOV-01/02]

- -CC - pipe flanges (stainless steel);
- -GC - pipe flanges (stainless steel);
- CV - bonnet/internals and bolting (stainless steel);
- ERV - body/internals (stainless steel);
- -HC - pipe flanges (stainless steel);
- HV - body and bonnet (forged or cast austenitic stainless steel [CASS]), stem (stainless steel);
- SG HX primary manway, manway cover (carbon steel), studs and nuts (alloy steel); secondary manway and manway cover plate (carbon steel), studs (alloy steel) and nuts (carbon steel), secondary handhole and handhole cover plate (carbon steel), studs (alloy steel) and nuts (carbon steel);
- SG HX tubes (Alloy 600);
- RCP seal water HX tubes (stainless steel);
- PUMP (RCP) case and pump cover (CASS), closure studs and nuts (carbon steel);
- Pressurizer manway forging and cover plate (carbon steel or alloy steel); and
- MOV - body/bonnets (austenitic stainless steel), for some MOVs with stainless steel discs and stems, and some MOV seats (stellite).

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately $134x10^6$ lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapters 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

As the interface between the primary and secondary fluids, the SG HX tubes are subjected to both the internal RCS environment and the internal SG environment.

The external RCS environment is ambient atmospheric air inside the Containment Building that is climate controlled. This environment in the Containment Building during normal operations has maximum humidity of 70% and maximum temperature of 120°F. [Reference 1, Table 9-18, Reference 29, Attachments 1, Table 1 page 13]

Group 2 (wear) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard abrasive particles (abrasive wear), or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). In addition to material loss from the above wear mechanisms, impeded relative motion between two surfaces held in intimate contact for extended periods may result in galling/self welding. Wear most typically occurs in components that experience considerable relative motion such as valves and pumps, in components that are held under high loads with no motion for long periods (i.e., valves, flanges), or in clamped joints where relative motion is not intended but occurs due to loss of clamping force (e.g., tubes in supports, valve stems in seats, springs against tubes). [Reference 2, Attachments 7, HX]

Wear can also occur between closures/closure cover plates and by flow induced vibrations causing a rubbing action between components. [Reference 2, Attachments 6, HX] Therefore, wear was determined to be plausible for the Group 2 components for which aging effects must be managed during the period of extended operation.

Group 2 (wear) - Methods to Manage Aging

Mitigation: Design features such as the proper design and material selection of the RCS device types susceptible to this ARDM can mitigate the effects of wear. Mechanical wear on those components that are manipulated during refueling operations can occur, but they usually are not subject to mechanical wear during normal operation. Minimizing the amount of component manipulation can mitigate wear.

Discovery: With proper design, mechanical wear occurs slowly over long periods of time and is revealed as material loss of the components themselves. This wear can be discovered and monitored by visual inspection of the affected areas. Visual inspections of components can find mechanical wear on the components.

Indications of wear identified during visual examinations of RCS components during refueling outages can be recorded and evaluated for potential damage. Evidence of this mechanical wear could then lead to corrective actions being taken to restore the design function of the affected components.

Group 2 (wear) - Aging Management Program(s)

Mitigation: There are no programs to mitigate the effects of wear other than the proper design and material selection for the intended application.

Discovery: The CCNPP Administrative Procedure MN-3-110, "ISI of ASME Section XI Components," is one of the existing programs designed to detect and manage the aging effects of wear for the RCS components susceptible to wear. [Reference 2, Attachments 8] The Inservice Inspection (ISI) Program

Plan responds to the requirements of Section XI of the ASME Code, 1983 Edition through Summer 1983 Addenda, and is subject to periodic update per 10 CFR 50.55a. [Reference 30, Section 1.2.1]

The scope of the existing ISI Program for the RCS includes examination and inspection of components identified in ASME Section XI (e.g., Subsection IWB, etc.). [Reference 31, Section 1.2A] The ISI Program is performed to meet the requirements of references identified in Section 1.2A of Reference 31. An extensive list of the developmental and performance references for the existing ISI program is provided in Section 2.0 of Reference 31.

Inservice inspection requirements in ASME Section XI, as implemented by the existing ISI Program, provide for visual examination of accessible surfaces of RCS components. [Reference 32, Table IWB-2500-1] The ASME Section XI ISI visual examination of the RCS components requires determining the general mechanical and structural conditions of the components from the effects of wear. Examinations may require, as applicable, determination of structural integrity, measurement of clearances, detection of physical displacements, structural adequacy of supporting elements, connections between load-carrying structural members, and tightness of bolting. [Reference 32, IWA-2213 Visual Examination VT-3]

If any abnormal condition is identified, the ASME Code provides requirements for the timely correction of the condition. [Reference 32, IWA-4130 Repair Program] Visual inspections can readily identify damage to the RCS components from wear. The corrective actions taken will ensure that the RCS components remain capable of performing their intended function under all CLB conditions.

The ISI Program is subject to internal and independent assessments and is recognized through these assessments as performing highly effective examinations and aggressively pursuing continuous improvements. Baltimore Gas and Electric Company monitors industry initiatives and trends in the area of ISI and non-destructive examination and plays a leadership role in developing, analyzing, and advancing non-destructive examination and ISI methods. The program is also subject to frequent external assessments by the Institute for Nuclear Power Operation, NRC, and others.

Operating experience relative to the ISI Program at CCNPP has been such that no site specific problems or events have required changes or adjustments. The program has been effective in its function of performing examinations required by ASME Section XI with respect to wear.

The CCNPP Boric Acid Corrosion Inspection (BACI) Program, MN-3-301, is credited with the discovery of wear of RCS components. The discovery of boric acid residue could indicate RCS leakage as the result of component wear. The ISI Program required the establishment of the Boric Acid Corrosion Monitoring Program to systematically ensure that boric acid corrosion does not degrade the primary system boundary. [Reference 31, page 23, Section 5.8.A.1.] The program controls examination and test methods and actions to minimize the loss of structural and pressure retaining integrity of RCS pressure boundary components due to boric acid corrosion. [Reference 31, Section 3.0.C] The basis for the establishment of the program is Generic Letter 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in pressurized water reactor (PWR) plants. [Reference 33, Section 1.1]

The scope of the program is threefold: (1) It provides examination locations where leakage may cause degradation of the primary pressure boundary by boric acid corrosion; (2) It provides examination requirements and methods for the detection of leaks; and (3) It provides the responsibilities for initiating engineering evaluations and the subsequent proposed corrective actions. [Reference 33, Section 1.2]

Under the BACI Program the VT-2 (a type of visual examination described in ASME XI, IWA-2212) walkdown examinations must be performed in accordance with ASME XI, IWA-2212, and the VT-1 examinations must be performed in accordance with ASME XI, IWA-2211. The VT-2 walkdown examinations must include the accessible external exposed surfaces of pressure-retaining, noninsulated components; floor areas or equipment surfaces located underneath noninsulated components; vertical surfaces of insulation at the lowest elevation where leakage may be detected and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas where water may be channeled for insulated components whose external insulation surfaces are inaccessible for direct examination; and for discoloration or residue on any surface for evidence of boric acid accumulation. Any leakage detected must be reported on an IR for corrosion degradation assessment. [Reference 33, Section 5.2]

Upon reaching reactor shutdown, ISI personnel are required to perform a containment walkdown visual inspection (VT-2) as soon as possible after attaining hot standby condition to identify and quantify any leakage found in specific areas of the Containment Building. A second ISI walkdown is performed prior to plant startup (at normal operating pressure and temperature) if leakage was identified and corrective actions taken. The ISI must ensure that all components that are subject of IRs where boric acid leakage has been found are examined in accordance with the requirements of this program. [Reference 33, Sections 5.1 and 5.2] Calvert Cliffs Administrative Procedure QL-2-100, "Issue Reporting and Assessment," defines requirements for initiating, reviewing, and processing IRs, and resolution of issues. The IRs are generated to document and resolve process and equipment deficiencies and nonconformances. [Reference 34, Sections 1.1 and 1.2]

Additionally, the program has evolved with regard to boric acid leaks discovered during other types of walkdowns and inspections. The program dictates a minimum qualification level of Level II Inspectors for the evaluation of boric acid leaks. Apparent leaks that are discovered during these other walkdowns/inspections are documented in IRs by the individual discovering the leak. These IRs are then routed to the ISI organization for closer inspection and evaluation by a Level II Inspector for disposition. This approach provides for more boric acid leakage inspection coverage and ensures boric acid leakage and its effects are properly evaluated.

Issue Reports that have been written in accordance with this program are required to address: (1) the removal of the boric acid residue; and (2) the inspection of the affected components for general corrosion. If general corrosion is found on a component, the IR is to provide an evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 33, Section 5.3]

Calvert Cliffs Technical Procedure RCS-10, "Pressurizer Manway Cover Removal and Installation," is also credited with the discovery of wear on the pressurizer components. The procedure contains steps that direct the user to inspect the studs (if they were not removed) for the presence of boric acid. The procedure also directs the user to contact the ISI organization to perform visual inspections of the pressurizer manway studs and nuts to ensure that they are acceptable for reuse. If boric acid is present, RCS-10 directs the cleaning and lubrication of the pressurizer manway studs and nuts. [Reference 35] Technical Procedure

RCS-10 is performed during refueling outages**.** This program has been observed to be historically effective in managing the applicable aging.

Calvert Cliffs Technical Procedures SG-1, "Steam Generator Secondary Manway Cover Removal," and SG-2, "Steam Generator Secondary Manway Cover Installation," are both credited with discovery of wear on the SG manway closure surfaces. Procedures SG-1 and SG-2 both direct the user to inspect the seating surfaces for defects, and if defects are found, to notify the job supervisor. The procedures also require the studs to be inspected prior to installation of the manway covers. [References 36 and 37] Both SG-1 and SG-2 are performed during refueling outages. This program has been observed to be historically effective in managing the applicable aging.

Calvert Cliffs Technical Procedures SG-5, "Steam Generator Secondary Handhole Cover Removal," and SG-6, "Steam Generator Secondary External Handhole Cover Installation," are both credited with discovery of wear on the SG secondary handhole closure surfaces. Procedures SG-5 and SG-6 both direct the user to inspect the seating surfaces for defects or smoothness, and if defects are found, to notify the job supervisor. [References 27 and 28] Both SG-1 and SG-2 are performed during refueling outages.

Calvert Cliffs Surveillance Test Procedures STP-M-574-1/2 are credited for discovering of wear on SG HX tubes. The procedure directs the user as to the sample size for tube inspection, inspection process, evaluation, and determination of tube status. Refer to Group 1 (denting) for a discussion of this surveillance program. [Reference 38 and 39]

Calvert Cliffs Surveillance Test Procedures STP-O-27-1/2, "Reactor Coolant System Leakage Evaluation," are credited for discovering wear on the RCS valve discs and seating surfaces. The procedure will discover wear on RCS valves by determining if any of them are leaking RCS coolant. Calvert Cliffs procedures STP-O-27-1/2 directs the user to perform calculations to determine the amount and potential source of RCS leakage. Any abnormal RCS leakage would be detected and actions taken to correct the leakage prior to a loss of the valve intended function. The basis for the acceptance criteria of leakage rates are provided by the CCNPP Technical Specifications. The CCNPP Surveillance Test Procedures STP-O-27-1/2 are performed in conjunction with CCNPP Technical Procedure CP-224, "Primary to Secondary Leak Rate." [Reference 40] This program has been observed to be historically effective in managing the applicable aging mechanism(s).

Calvert Cliffs Technical Procedure SG-20, "Steam Generator Primary Manway Cover Removal and Installation," is credited with the discovery of wear on the SG primary manway flange seating surfaces. The procedure directs the user to inspect the SG primary manway flange sealing surfaces for flaws and to clean the gasket surface areas. In addition, SG-20 requires the user to ensure that all studs and nuts have been inspected by BGE's Materials Engineering and Inspection Unit prior to installation. [Reference 41] This procedure is performed during plant refueling outages. This program has been observed to be historically effective in managing the applicable aging.

Calvert Cliffs will continually review industry activity and experience with respect to wear of tube in tube RCP seal water heat exchangers with CCNPP Administrative Procedure NS-1-100, "Use of Operating Experience and the Nuclear Hotline." Calvert Cliffs will take appropriate actions if any wear-induced pressure boundary leakage occurs in RCP seal water heat exchangers. [Reference 2, Attachments 8, 10]

Group 2 (wear) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the components listed under the Materials and Environment section that are susceptible to wear:

- The Group 2 components listed above provide the RCS pressure-retaining boundary and containment isolation function, so their integrity must be maintained under CLB design conditions.
- Wear is plausible for the Group 2 components mentioned above. Wear could result in the loss of component material and lead to the loss of the passive intended functions.
- The CCNPP Administrative Procedure MN-3-110 provides for the inspection of Group 2 components per the requirements of ASME Section XI. Though wear cannot be completely prevented, the status of pressure-retaining components can be evaluated on a basis that allows for corrective actions to be taken as conditions indicate component wear.
- The CCNPP BACI Program provides for examination of potential corrosion of the Group 2 components described above and subsequent cleanup of any boric acid residue present on them.
- The CCNPP Technical Procedure RCS-10 provides for the inspection of the pressurizer manway seating surfaces for wear and manway studs/nuts for the presence of boric acid.
- The CCNPP Technical Procedures SG-1 and SG-2 provide for the discovery of wear on the SG manway closure surfaces.
- The CCNPP Technical Procedures SG-5 and SG-6 provide for the discovery of wear on the SG handhole closure surfaces.
- The CCNPP Technical Procedures STP-M-574-1/2 are credited for discovering wear on the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.
- The CCNPP Surveillance Test Procedures STP-O-27-1/2 are credited for discovering wear on the RCS valve discs and seating surfaces that perform a pressure boundary function by performing RCS leak rate calculations. The RCS is subject to Technical Specifications for addressing any abnormal leakage.
- The CCNPP Technical Procedure SG-20 requires inspection for wear/flaws on the SG primary manway cover flange seating surfaces.
- Calvert Cliffs will continually review industry experience for RCP seal water HX tube wear in accordance with CCNPP Administrative Procedure NS-1-100. Calvert Cliffs will take appropriate action if the industry experiences degradation of these HXs resulting from tube wear.

Therefore, there is reasonable assurance that the effects of wear will be managed in order to maintain the pressure boundary integrity for the Group 2 components listed above under all design conditions required by the CLB during the period of extended operation.

Group 3 (erosion/erosion corrosion) - Materials and Environment

Table 4.1-3 shows that erosion is plausible for some RCP components and erosion corrosion is plausible for some SG HX components. These susceptible RCS components and their material characteristics are: [Reference 2, SG HX, PUMP-01, Attachments 4, 5, 6]

- SG HX - main steam outlet nozzles forging (alloy steel), secondary manway and manway cover plate (alloy steel), secondary handhole (carbon steel), and handhole cover plate (alloy steel); and
- RCP - case and pump cover (CASS).

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

Group 3 (erosion/erosion corrosion) - Aging Mechanism Effects

Erosion is caused by the high-velocity steam, water, or two-phase mixture (which may include particles) impinging on materials or leaking from joints. This mechanical wear or abrasion can be characterized by grooves, gullies, waves, holes, or valleys on a metal surface. Erosion corrosion is the acceleration of a corrosive process because of the erosion of the protective oxide film, which results in chemical attack or dissolution of the underlying metal. Erosion corrosion also occurs in environments with high velocity water (single or two-phase) having flow disturbances, low oxygen content, and fluid pH < 9.3. Erosion corrosion is also increased by component geometries that cause disturbances in the flow stream. [Reference 2, Attachments 7, Valve]

The specified SG HX components are subjected to environments that are conducive to erosion corrosion, while the specified RCP components are subjected to environments conducive to erosion. Therefore, erosion and erosion corrosion were determined to be plausible ARDMs for the Group 3 components for which aging effects must be managed. [Reference 1, Attachments 6s, HX, PUMP]

Group 3 (erosion/erosion corrosion) - Methods to Manage Aging

<u>Mitigation:</u> Design features, such as the proper material selection (and proper installation) of the RCS device types susceptible to these ARDMs, can mitigate the effects of erosion/erosion corrosion.

<u>Discovery</u>: Erosion and erosion corrosion can occur over time and are revealed as material loss of the components themselves. These effects can be discovered and monitored by visual inspection of the potentially affected areas. Visual inspections of these components could find any potential erosion/erosion

corrosion on the components. Programs that monitor erosion corrosion could be utilized as a means of tracking and discovering the onset of these aging mechanisms before the RCS components fail to perform their intended function.

Programs/procedures that look for RCS leakage also augment the management of erosion/erosion corrosion by discovering leakage and performing subsequent corrective actions that would alleviate conditions leading to these ARDMs.

Group 3 (erosion/erosion corrosion) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of erosion/erosion corrosion. The following discovery programs can limit the effects of these ARDMs by taking corrective actions when they are discovered.

Discovery: The CCNPP Administrative Procedure MN-3-110 is one of the existing programs designed to detect and manage the aging effects of erosion corrosion of the SG main steam outlet nozzles. [Reference 2, Attachments 8 TPR] The ISI Program refers to an ultrasonic procedure that examines the SG main steam outlet nozzle inner radius area. This procedure directs the user to refer to the ASME Boiler and Pressure Vessel Code Section XI, Table IWB-3512-1 for evaluation criteria of the ultrasonic examination results. [Reference 42] Refer to the previous discussion of the ISI Program under Group 2 (wear) under Aging Management Programs.

Calvert Cliffs BACI Program is credited with the discovery of erosion of the joint before the RCP case and pump cover. The procedure requires investigation of any boric acid leakage that is found on these components during walkdowns. Refer to the previous discussion of the BACI Program under Group 2 (wear) - Aging Management Programs.

Group 3 (erosion/erosion corrosion) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the Group 3 components:

- The Group 3 components provide a pressure-retaining boundary for the RCS, so their integrity must be maintained under CLB design loading conditions.
- Erosion is plausible for RCP components listed above. This could result in the loss of component material and lead to the loss of the pressure-retaining boundary function.
- Erosion corrosion is plausible for the SG main steam outlet nozzles. This could result in the loss of component material and lead to the loss of the pressure-retaining boundary function.
- Calvert Cliffs' ISI Program is credited with the discovery of erosion corrosion on the SG main outlet nozzles using ultrasonic examinations. The program requires the performance of corrective actions before a pipe/nozzle wall thins to below the minimum required wall thickness necessary for the pipe/nozzle to perform its intended function.
- Calvert Cliffs BACI Program is credited with the discovery of erosion on the joint before the RCS case and pump cover. This program also provides for examination of potential corrosion of the

RCS device types described above and subsequent cleanup of any boric acid residue present on them.

Therefore, there is reasonable assurance that the effects of erosion and erosion corrosion will be managed in order to maintain the pressure boundary integrity for the RCS device types listed above under all design conditions required by the CLB during the period of extended operation

Group 4 (fatigue) - Materials and Environment

Table 4.1-3 shows that fatigue is plausible for some of the RCS device types. These susceptible RCS device types and their material characteristics are: [Reference 2, -CC-01/02/03/04/05/06, -GC-01/02/03/04/05/06, CKV-01, CV-01, ERV-01, HX-01, MOV-01/02, PUMP-01, PZV-01, RV-01 Attachments 4, 5, 6]

- -CC - includes all piping subcomponents such as nozzles, forgings, welds, safe ends, and thermal sleeves (piping is stainless steel, safe ends are CASS);
- -GC - pipe (stainless steel), flanges (stainless steel), bolting studs (alloy steel), bolting hex nuts (carbon steel), welds (stainless steel);
- CKV - body/bonnet (stainless or carbon steel) and bolting (carbon steel);
- CV - body/bonnet (CASS) and bonnet/internals (stainless steel);
- ERV - cage (CASS) and body/internals (stainless steel);
- SG HX - lower shell segments, upper shell segment, upper cone segment, top head peel segments (carbon steel), top head dome segment, steam outlet nozzle forging, steam outlet safe end, feedwater nozzle forging, feedwater nozzle safe end (alloy steel), and secondary welds (alloy steel);
- MOV - body/bonnet (austenitic stainless steel, stainless steel), disc and stem (CASS and stainless steel), and seat (stellite on CASS);
- PUMP - (RCP) case and pump cover (CASS), closure studs and nuts (carbon steel);
- PZV - all pressurizer subcomponents are susceptible to fatigue (main shell, head and bottom plates are alloy steel with stainless steel or Alloy 600 cladding); and
- RV - base (austenitic stainless steel), nozzle (alloy steel), disc (CASS).

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^{6} lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained. The RCS components listed are subject to thermal and mechanical cyclic loading during RCS heat-up and cool-down and other plant operational events.

Group 4 (fatigue) - Aging Mechanism Effects

Low-cycle fatigue is a mechanism that initiates and propagates flaws under the influence of fluctuating or cyclic applied stress. Fatigue is influenced by variables that include: mean stress, stress range, environmental conditions, surface roughness, and temperature. Thermal stresses develop when a material is heated or cooled. Generally, fatigue failures occur at stresses having a maximum value less than the yield strength of the material. If a component is repeatedly subjected to loads of sufficient magnitude, a fatigue crack or cracks will eventually be formed in some highly stressed region and may gradually progress through the metal until complete fracture occurs. [Reference 43, page 4-7] The cracks may then propagate under continuing cyclic stresses.

The fatigue life of a component is a function of several variables such as stress level, stress state, cyclic wave form, fatigue environment, and the metallurgical condition of the material. Failure occurs when the endurance limit number of cycles (for a given load amplitude) is exceeded. [Reference 2, Attachments 7s]

The RCS device types listed above are subject to a wide variety of varying mechanical and thermal loads. [Reference 2, Attachments 7s] Plant transients apply cyclical thermal loading and pressurization that contribute to fatigue accumulation on the RCS device types above. The limiting locations for low-cycle fatigue in the RCS and their controlling transients are: [Reference 44, Table 5-1]

- Pressurizer Spray System - cycle of the pressurizer spray;
- Safety injection nozzle - plant cooldown (initiation of shutdown cooling);
- Charging inlet nozzle - loss of charging flow and recovery, loss of letdown flow and recovery, regenerative heat exchanger isolation;
- Pressurizer surge nozzle - pressurizer heatup and plant cooldown;
- SG secondary shell - initiation of main feedwater, initiation of auxiliary feedwater;
- SG feedwater nozzle - initiation of main feedwater;
- Pressurizer bottom head and support skirt - plant cooldown, reactor trip;
- Shutdown cooling outlet nozzle - plant cooldown; and
- SG tube-to-tubesheet weld - primary leak test RCS heatup.

American Society of Mechanical Engineers Section III requires the design analysis for Class 1 components to address fatigue and establishes limits such that initiation of fatigue cracks is precluded. Section III defines the fatigue threshold in terms of a cumulative fatigue usage factor (CUF). The low-cycle fatigue "damage" from a particular transient depends on the magnitude of the stresses applied. The summation of fatigue usage over all transients of all types is the CUF. Crack initiation is conservatively assumed to have occurred at a CUF equal to one.

The CUF can be determined from the actual or predicted transient history for the component and limits established on the number of transients.

Group 4 (fatigue) - Methods to Manage Aging

Mitigation: The effects of low-cycle fatigue can be mitigated by operational practices that reduce the number and severity of thermal transients on the RCS components and by proper design and material selection. Therefore, the effects of fatigue can be mitigated by operational practices that reduce the number and severity of pressure and thermal transients, by fuel management practices that minimize the number of refuelings, and by proper design and material selection.

Discovery: Fatigue cracks can be discovered by inspecting components, and the scope and frequency of inspections can be established based on the likelihood that fatigue cracks have initiated. As discussed above, low-cycle fatigue is accounted for in the original design in accordance with ASME Code Section III. Monitoring the number of design-basis transients and/or the accumulated fatigue usage can be used to predict the end of fatigue life.

American Society of Mechanical Engineers Code Section III also provides accepted practices for analyzing Class I components for thermal fatigue combined with all other loads that must be considered under the CLB. An inspection program designed to identify crack initiation can be effective in discovering the effects of this aging mechanism prior to loss of the RCS pressure boundary function. The RCS components listed above can be inspected during plant refueling outages.

Group 4 (fatigue) - Aging Management Program(s)

Mitigation: As part of general operating practice, plant operators minimize the duration and severity of transitory operational cycles. Further modification of plant operating practices to reduce the magnitude and/or frequency of thermal transients would place additional unnecessary restrictions on plant operations. This is because the detection and monitoring activities discussed below are deemed adequate for effectively managing fatigue in the RCS. No credit has been given to the 24-month fuel cycle since plant transients other than refueling could cause plant heat-ups and cool-downs.

Discovery: The CCNPP Fatigue Monitoring Program (FMP) records and tracks the number of critical thermal and pressure test transients. Cycle counting is performed as part of this program. The data for thermal transients is collected, recorded, and analyzed using a safety-related software package. The software is used to analyze data that represents real transients and to predict the number of transients for 40 and 60 years of plant operation based on the historical records. This information is used to verify that the RCS critical locations will not experience more than the allowable number of cycles for those locations. [Reference 44, Tables 4-1, 4-7, Reference 45] The Improved Standard Technical Specifications for CCNPP, which will be implemented in 1997, will contain a requirement for tracking cyclic and transient occurrences to ensure that components are maintained within the design limits.

The current FMP monitors and tracks low-cycle fatigue usage for the limiting components of the NSSS and the SG safe-ends-to-reducer welds. Eleven locations in these systems have been selected for monitoring for low-cycle fatigue usage; they represent the most bounding locations for critical thermal and pressure transients and operating cycles. [References 44 and 45] The RCS critical (or bounding) locations and their controlling transients for fatigue are listed above in the Aging Management Effects section. [Reference 44, Sections 4.1, 4.8] A one-time fatigue analysis will be performed for the RCPs, MOVs, and pressurizer

RVs to determine if these components are bounded by components and transients currently included in the FMP. If these components are not bounded they will be added to the FMP. [Reference 2, Attachments 10]

The original design fatigue analysis of the RCS components (which was incorporated into the FMP) determined the critical locations and corresponding transients. All transients that contribute to low-cycle fatigue usage are accounted for as part of the original design fatigue analysis. The FMP only tracks certain critical transients (see list of transients and components under Methods to Manage Aging). The contribution to fatigue usage for all other design transients is accounted for by an "initial" fatigue usage. The software package adds subsequent fatigue usage resulting from RCS pressure and temperature transients to "initial" fatigue usage to obtain the current CUF. [Reference 44, Sections 4.1, 4.8, Reference 46]

The current FMP tracks low-cycle fatigue usage using both cycle counting and stressed-based analysis. In accordance with ASME Code Section III, the fatigue life of a component is based on a calculated CUF of less than or equal to one. The CUF and actual number of transients for limiting locations in the NSSS and SGs are determined using plant thermal and pressure data. The CUF for several locations, including the pressurizer surge line, is also calculated using stress-based analysis techniques. [References 45, 46, and 47]

Plant parameter data is collected on a periodic basis and reviewed to ensure that the data represents actual transients. Valid data are entered into the software, which counts the critical transient cycles and calculates the CUFs. Based on ASME Code Section III, a CUF less than or equal to one, and/or the number of cycles remaining below the design allowable number, are acceptable conditions for any given component since no crack initiation would be predicted.

The number of cycles and CUF are calculated on a semi-annual basis, which provides a readily predictable approach to the alert value. [Reference 47, Section 1.1] In order to stay within the design basis, corrective action is initiated well in advance of the CUF approaching one or the number of cycles approaching the design allowable, so that appropriate corrective actions can be taken in a timely and coordinated manner. [Reference 47]

Modifications have been made to the FMP recognizing lessons learned. For example, analysis techniques, such as stress-based analysis, have been implemented for locations that have unique thermal transients or involve unique geometry. Other modifications have been made to reflect changes or proposed changes to plant operating practices, and to reflect plant operating conditions more accurately. The plant design change process requires the FMP to consider any proposed changes that affect the fatigue design basis or transient definitions. [References 45 and 48]

The CCNPP FMP has been inspected by the NRC, which noted that this monitoring system can be used to identify components where low-cycle fatigue usage may challenge the remaining and extended life of the components and can provide a basis for corrective action where necessary. The program is controlled in accordance with EN-1-300, "Implementation of Fatigue Monitoring." [Reference 49] Since the FMP has been initiated, no locations have reached their design allowable number of cycles or a CUF of greater than or equal to one. The CUFs through 1996 for the RCS components listed above are: [Reference 45]

	Unit 1	Unit 2
• Pressurizer Spray System	0.33877	0.32699
• Safety Injection Nozzle	0.00992	0.00925
• Charging Inlet Nozzle 1	0.11515	0.11615
• Charging Inlet Nozzle 2	0.11515	0.11616
• Pressurizer Surge Nozzle	0.13137	0.09635
• SG Secondary Shell 1	0.08957	0.09110
• SG Secondary Shell 2	0.08951	0.09133
• Pressurizer Bottom Head and Support Skirt	0.26150	0.23734
• Shutdown Cooling Outlet Nozzle	0.15917	0.12896
• SG Tube-to-Tubesheet Weld 1	0.02653	0.02653
• SG Tube-to-Tubesheet Weld 2	0.02653	0.02653

To further address fatigue for license renewal, CCNPP participated in an EPRI-sponsored task to demonstrate the industry fatigue position. The task applied industry-developed methodologies to identify fatigue-sensitive component locations that may require further evaluation or inspection for license renewal and evaluate environmental effects as necessary. The program objective included the development and justification of aging management practices for fatigue at various component locations for the renewal period. The demonstration systems were the Feedwater System, the pressurizer surge line, and the Charging/Letdown System. [Reference 4, Page 3]

Generic Safety Issue 166

Generic Safety Issue 166, Adequacy of Fatigue Life of Metal Components, presents concerns identified by the NRC that must be evaluated as part of the license renewal process. The NRC staff concerns about fatigue for license renewal fall into five categories: The first is adequacy of the fatigue design basis when environmental effects are considered. This concern does not apply to the RCS because of stringent RCS water chemistry controls, exceptionally low oxygen concentrations (less than 5 parts per billion), and because the RCS carbon steel interior surfaces are clad with stainless steel. The second category concerns the adequacy of both the number and severity of design basis transients. Since these have already been analyzed for the CCNPP RCS, this concern does not apply. A third category, adequacy of ISI requirements and procedures to detect fatigue indications, does not apply because CCNPP does not rely on ISI as the sole means for detection of fatigue. Category four, adequacy of the fatigue design basis for Class I piping components designed in accordance with American Nuclear Standards Institute B31.1, does not apply because the RCS does not have piping components designed in accordance with B31.1. The fifth and last category, adequacy of actions to be taken when the fatigue design basis is potentially compromised, are adequately addressed by the CCNPP FMP. [Reference 50, 110]

Group 4 (fatigue) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the RCS components subject to low-cycle fatigue:

- The Group 4 components provide a pressure-retaining boundary for the RCS, so their integrity must be maintained under CLB design conditions.
- Low cycle fatigue is plausible for the Group 4 device types listed above.
- If left unmanaged, low-cycle fatigue could result in crack initiation and growth, which could impair the pressure-retaining function.
- The Group 4 device types are the bounding fatigue sensitive components for the RCS and are expected to bound the other RCS components for the effects of fatigue.
- The CCNPP FMP tracks all applicable plant transients and monitors the cycles and fatigue usage for the bounding RCS components.
- The FMP is controlled so that effective and timely corrective actions can be taken prior to a loss of RCS pressure boundary integrity resulting from fatigue damage.
- A one-time fatigue analysis will be performed for the RCPs, MOVs and pressurizer RVs to determine if these components are bounded by components and transients currently included in the FMP. If these components are not bounded they will be added to the FMP.
- Tracking the cycle and fatigue usage for the bounding RCS components will ensure that they and all other RCS components will not exceed their fatigue design basis.

Therefore, there is reasonable assurance that the effects of fatigue in RCS components will be managed in order to maintain the components' intended function under all design loading requirements of the CLB during the period of extended operation.

Group 5 (galvanic/general corrosion and pitting) -Materials and Environment

Table 4.1-3 shows that galvanic, general corrosion, and pitting are plausible for some of the RCS components. The RCS subcomponents listed below are susceptible to one or more of these ARDMs. These susceptible RCS components and their material characteristics are: [Reference 2, -CC-01/02/03/04, -GC-01/02/03/04/05/06, CKV-01, ERV-01, HV-04, HX-01, MOV-02, PUMP-01, PZV-01, RV-01, Attachments 4, 5, 6]

<u>General Corrosion - External</u>

- -CC - pipe, elbows, and nozzle forging (carbon steel), bolting studs (alloy steel), bolting hex nuts (carbon steel);
- -GC - bolting studs and bolting hex nuts (carbon steel);
- CKV - some of the CKVs bolting (carbon steel);
- ERV - bracket stud (alloy steel) and nut (carbon steel);

- SG HX - primary manway (alloy steel, clad - Alloy 600), manway cover plate (carbon or alloy steel), primary head torus (carbon steel with stainless steel clad), spherical head (carbon steel); secondary manway studs (alloy steel) and hex nuts (carbon steel), secondary manway yoke (carbon steel), handhole studs and nuts (alloy steel); primary manway studs and nuts (alloy steel); lower support sliding base and cap plate (carbon steel), lower support flange bolts (alloy steel), and flange nuts (carbon steel);
- MOV - bonnet stud and nut (carbon steel);
- PUMP - closure studs and nuts (carbon steel);
- Pressurizer - alloy steel shell, top head and bottom head (alloy steel); safety/relief valves, spray and surge nozzle forgings (forged alloy steel); manway forging (alloy steel), manway cover plate (carbon steel), manway bolting studs and bolts (alloy steel); carbon steel welds; support ring assembly and base ring assembly (carbon steel), support skirt forging (alloy steel), and lifting lugs (carbon steel); and
- RV - bonnet/spring/bonnet studs (carbon or alloy steel).

General Corrosion - Internal

- SG HX tube support structures (carbon steel components of various Grades and Classes)

Galvanic Corrosion - External

- HV - stem, disk and seat (stainless steel).

Pitting - Internal

- SG HX - tubes (Alloy 600) exposed to the SG internal (secondary side) environment.

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates, and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

As the interface between the primary and secondary fluids, the SG HX tubes are subjected to both the internal RCS environment and the internal SG environment.

The external RCS environment is ambient atmospheric air inside the Containment Building that is climate controlled. This environment in the Containment Building during normal operations has maximum humidity of 70% and maximum temperature of 120°F. [Reference 1, Table 9-18, Reference 29, Attachments 1, Table 1 page 13]

For RCS carbon steel components clad on the interior surfaces with stainless steel, only exterior surfaces could be susceptible to the ARDMs in this group. The RCS contains boric acid that could leak onto the exterior of these carbon steel components. [Reference 2, Attachments 6s and 7s]

Group 5 (galvanic/general corrosion and pitting) - Aging Mechanism Effects

General corrosion is degradation that results in wall thinning (wastage) due to chemical attack (dissolution) by an aggressive environment to materials susceptible to that environment. An important concern is the leakage of boric acid on carbon steel components. Boric acid attacks and damages the components clad internally with stainless steel from the their exterior (carbon steel) surfaces. The consequences of the damage are a loss of load carrying cross-sectional area. General corrosion could lead to excessive wall thinning and failure of the RCS pressure boundary function for the RCS components. [Reference 2, Attachments 7s]

Galvanic corrosion is accelerated corrosion caused by dissimilar metals in contact in a corrosive or conductive solution. Galvanic corrosion requires two dissimilar metals in physical or electrical contact, developed electrical potential (material dependent), conducting solution, and a corrosive environment (i.e., oxygen or chlorides for example). [Reference 2, Attachments 7s]

Pitting is a form of localized general corrosion that results in holes in a metal. Pitting can lead to penetrations of the pressure boundary with a small amount of metal loss. Carbon steels, stainless steels, and Alloy 600 are susceptible to pitting in various degrees. Severe pitting of CE SG tubes has occurred at other power plants. [Reference 2, HX01, Attachments 7]

If left unmitigated in the long-term, galvanic/general corrosion could eventually result in failure of the Group 5 components pressure-retaining capability under CLB design loading conditions.

Group 5 (galvanic/general corrosion and pitting) - Methods to Manage Aging

Mitigation: The effects of these ARDMs cannot be completely prevented, but they can be mitigated by minimizing the exposure of the carbon steel surfaces of the RCS metal components to an aggressive chemical environment. Stainless steel cladding on the interior of some RCS components helps to reduce the effects of galvanic/general corrosion on the interior surfaces exposed to reactor coolant. However, mitigation of corrosion on the exterior surfaces of the Group 5 components requires minimization of RCS leakage from the RCS pressure boundary, and the removal of any boric acid residue from exterior RCS surfaces.

Discovery: The effects of galvanic/general corrosion on the RCS components can be discovered through a program of visual inspections on the RCS areas susceptible to these ARDMs. Inspection of the areas around the RCS components would identify leakage occurring and result in corrective actions being taken before corrosion could degrade the RCS intended function. Those Group 5 components that are not accessible to visual inspection (i.e., SG HX tubes - pitting) can be examined using remote sensing techniques.

Group 5 (galvanic/general corrosion and pitting) - Aging Management Program(s)

Mitigation:

External: The CCNPP BACI Program will mitigate the effects of boric acid corrosion on external carbon steel surfaces through discovery of minor leakage of RCS components and removal of any boric acid residue that is found during walkdown inspections. Removal of any boric acid leakage from component surfaces mitigates the effects of this substance on these surfaces. This program was previously described in Group 2 (wear) under Aging Management Programs.

Discovery:

External: Discovery of galvanic/general corrosion for RCS components is performed by the CCNPP BACI Program and Technical Procedure SG-20. These programs and procedures require the visual inspection of RCS components for boric acid leakage and corrosion. The CCNPP BACI Program is credited with discovery of galvanic/general corrosion for those RCS components listed as susceptible to these ARDMs. This program requires investigation of any boric acid leakage that is discovered. The BACI Program was previously discussed in Group 2 (wear) under Aging Management Programs. [Reference 2, Attachments 8]

The CCNPP MN-3-110, ISI of ASME Section XI Components, is credited with discovering galvanic/general corrosion on the RCP components and discovering general corrosion on RCS piping (pipe code -CC). Visual examination (VT-2) of external surfaces are performed for these RCS components in accordance with ASME Section XI IWA-2212. [Reference 2, Attachments 8]

The CCNPP Technical Procedure SG-20 is credited with the discovery of general corrosion on the SG primary manway bolting materials. The procedure directs the user to inspect the SG primary manway flange sealing surfaces for flaws and to clean the gasket surface areas. In addition, SG-20 requires the user to ensure that all studs and nuts have been inspected prior to installation. [Reference 41] This procedure is performed during plant refueling outages.

Internal: The CCNPP Technical Procedures STP-M-574-1/2 are credited for discovering pitting on SG HX tubes. The procedure implements the inspection requirements of the CCNPP Technical Specifications and defines the sample size for tube inspection, inspection process, evaluation, and determination of tube status. This procedure was previously described in Group 2 (wear) under Aging Management Programs. [References 38 and 39]

For internal corrosion of SG HX tube support structures, BGE is aware of SG flow-assisted corrosion at the San Onofre Nuclear Generating Station and will monitor industry activity related to this aging mechanism. Calvert Cliffs will respond to any NRC generic communications on this matter as part of the CLB. An evaluation of flow-assisted corrosion for CCNPP SGs will be incorporated into annual updates of the BGE LRA.

The corrective actions taken as a result these programs will ensure that the RCS components remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 5 (galvanic/general corrosion and pitting) - Demonstration of Aging Management

Based on the material presented above, the following conclusions can be reached with respect to the galvanic/general corrosion and pitting of the Group 5 components:

- The Group 5 components provide a pressure-retaining boundary, and their integrity must be maintained under CLB design loading conditions.
- General corrosion is plausible for the Group 5 components listed as susceptible, which could lead to loss of pressure-retaining boundary integrity.
- Galvanic corrosion is plausible for the Group 5 hand valves, which could lead to loss of pressure-retaining boundary integrity.
- Pitting is plausible for the SG HX tubes, which could lead to loss of pressure-retaining boundary integrity.
- The CCNPP BACI Program provides for examination of potential galvanic and general corrosion of the RCS external surfaces and subsequent cleanup of any boric acid residue.
- The CCNPP ISI Program provides for the inspection of RCS pipe and RCPs, per the requirements of ASME Section XI, for galvanic/general corrosion. Though galvanic/general corrosion cannot be completely prevented, the status of these components can be evaluated on a regular basis and corrective actions can be taken as conditions indicate general corrosion.
- Calvert Cliffs Technical Procedure SG-20 will provide for the discovery of general corrosion or flaws on the SG primary manway cover flange seating surfaces and primary manway studs/nuts.
- Calvert Cliffs Technical Procedures STP-M-574-1/2 are credited for discovering pitting of the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.
- Examinations will be performed and appropriate corrective actions will be taken if galvanic/general corrosion or pitting are discovered.

Therefore, there is reasonable assurance that the effects of galvanic/general corrosion and pitting on RCS components will be managed in order to maintain the components pressure boundary integrity under all design conditions required by the CLB during the period of extended operation.

Group 6 (IGA) - Materials and Environment

Table 4.1-3 shows that IGA is plausible for the RCP seal water HXs, which are subjected to both the RCS and CC System environment. The RCP seal water HXs are fabricated from stainless steel. [Reference 2, HX-02, Attachments 4, 5, 6]

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control. The internal environment of the CC

System is chemically-treated water at a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 1, Section 9.5.2.1, Table 9-17]

Group 6 (IGA) - Aging Management Effects

Intergranular attack is similar to IGSCC, except that stress is not required for IGA. Intergranular attack is localized corrosion at or adjacent to grain boundaries, with relatively little corrosion of the material grains. It is caused by impurities in the grain boundaries, or the enrichment or depletion of alloying elements at grain boundaries, such as the depletion of chromium at austenitic stainless steel grain boundaries. Nickel alloys, such as Alloy 600. experience IGA in the presence of certain sulfur environments at high temperatures or when austenitic stainless steel weld filler material is inadvertently used on Ni-Cr-Fe alloys. The susceptibility of IGA can often be corrected by redistributing alloying elements more uniformly through solution heat treatment, by modifying the alloy to increase resistance to segregation, or by using a completely different alloy. [Reference 2, HX-02, Attachments 7s]

Group 6 (IGA) - Methods for Managing Aging

Mitigation: The effects of IGA can be mitigated on RCP seal water HXs by minimizing the exposure of the internal surfaces of the components to an aggressive environment. Maintaining system chemistry conditions to minimize impurities can limit the rate and effects of degradation due to these ARDMs.

Discovery: There are no feasible methods to discover IGA on the RCP seal water HXs other than indications of RCS leakage into the CC System. This RCS leakage is detected by radiation monitors in the CC System.

Group 6 (IGA) - Aging Management Program(s)

Mitigation: The effects of IGA will be mitigated for the RCP seal water HX by CCNPP Chemistry Procedure CP-204, "Specification and Surveillance Primary Systems," and CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems." Maintaining an RCS and CC System chemistry with minimal impurities will aid in the preventing IGA. [Reference 2, Attachments 1]

CP-204

Calvert Cliffs Technical Procedure CP-204 is credited with mitigating the effects of IGA on the RCP seal water HX (RCS side) by monitoring and maintaining the RCS chemistry. The chemistry controls provided by CP-204 have been established to: minimize impurity ingress to plant systems; reduce corrosion product generation, transport, and deposition; reduce collective radiation exposure through chemistry; improve integrity and availability of plant systems; and extend component and plant life. Maintaining system chemistry conditions to minimize impurities limits the rate and effects of component degradation. CP-204 is based on the Technical Specifications, BGE's interpretation of industry standards, and recommendations made by CE. [Reference 51, Sections 1.0, 2.0; Reference 52, Section 6.1.A]

The scope of CP-204 includes the following systems/components: [Reference 11, Section 2.0]

- Reactor Coolant (Modes 1 through 6);
- Spent Fuel Pool (Modes 1 through 6);

- Refueling Water Storage Tank (Modes 1 through 6);
- Refueling Pool (Mode 6);
- Safety Injection Tanks (Modes 1 through 6);
- High Pressure Safety Injection Pump Discharge (Modes 1 through 6);
- Boric Acid Storage Tank (Modes 1 through 6);
- Reactor Coolant Waste Receiver Tank (Modes 1 through 6);
- Reactor Coolant Waste Evaporator Bottoms (Modes 1 through 6);
- Boric Acid Batching Tank (Modes 1 through 6);
- Chemical and Volume Control Ion Exchangers (Modes 1 through 6); and
- Spent Fuel Pool Ion Exchangers.

Calvert Cliffs Technical Procedure CP-204 lists the parameters to monitor (e.g., chloride, fluoride, sulfate, oxygen, pH), the frequency of monitoring these parameters, and the acceptable value or range of values for each parameter. The primary chemistry parameters are measured at procedurally-specified frequencies (e.g., daily, weekly, monthly) and are compared against "target values," which represent a goal or predetermined warning limit. If a target value is approached or violated, corrective actions are taken as prescribed by the procedure, thereby ensuring timely response to chemical excursions. [Reference 50, Sections 3.0.C.4, 6.0]

The chemistry program at CCNPP (which includes CP-204) is subject to internal assessment activity both within the Chemistry Department and through the site performance assessment group. The program is also subject to external assessments by Institute for Nuclear Power Operations, NRC, and others. Operating experience relative to the chemistry program at CCNPP has shown it has been effective in its function of minimizing corrosion and corrosion-related failures and problems.

Calvert Cliffs Technical Procedure CP-204 provides for a prompt review of primary system chemistry parameters so that steps can be taken to return chemistry parameters to acceptable levels (within Technical Specification limits), and thus minimizing impurities and limiting the rate and effects of degradation due to corrosion mechanisms. [Reference 2, Attachments 8; Reference 50, Section 2.0]

CP-206

Calvert Cliffs Technical Procedure CP-206 is credited with mitigating IGA on the RCP seal water HX (CC System side) by monitoring and maintaining CC chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water that aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 53, Attachments 8]

Calvert Cliffs Technical Procedure CP-206 describes the surveillance and specifications for monitoring the CC System fluid. The procedure lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the CC System fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (normally not a radioactive system). [Reference 54, Attachments 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. For pH, the current action level is less than 9.0 or greater than 9.8; for hydrazine the current action level is less than 5 or greater than 25 parts per million (ppm). Refer to Attachments 1 in CP-206 for the specific monitoring frequency and target values for each chemistry parameter. [Reference 54, Attachments 1]

Operational experience related to CP-206 has shown no problems related to use of this procedure with respect to the CC System. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added as a parameter to CP-206 to discover any unusual corrosion of the CC carbon steel components.

An internal BGE chemistry summary report for 1996 described the CCNPP Units 1 and 2 CC/Service Water Systems' chemistry as excellent. Action levels for all four systems were only exceeded on eight occasions, or approximately 0.7% of the time during the year. Over 70% of the action levels exceeded were due to major system changes during the 1996 refueling outage. Recommendations to correct this condition have been made to determine outage evolutions that can affect the CC/Service Water System chemistry and take action to prevent chemistry targets being exceeded.

The CC System usually operates within normal parameters, except when the system is restarted after an outage lay-up. During an outage lay-up, the affected CC components may experience some minor corrosion when the internal component surfaces are exposed to air. After the CC System is returned to service and flow is once again established, some of this minor corrosion is removed from the pipe inner surface and released into the system where it is detected. An increase in suspended solids (due to this effect) was seen on Unit 1 at the start of the 1996 outage, and was correlated to flow initiation through the shutdown cooling HXs. The level of suspended solids slowly decreased over the course of the year back to levels obtained before the outage. The Unit 2 suspended solids showed a fairly steady baseline with a few minor spikes occurring during the year.

Procedure CP-206 provides for a prompt review of CC chemistry parameters so that steps can be taken to return chemistry parameters to normal levels, and thus minimizes the effects of crevice corrosion/pitting.

<u>Discovery</u>: Procedure CP-206 is credited with the discovery of wear in the RCP seal water HX. If the HXs were to corrode through, radiation monitors on the CC System would detect this leakage from the RCS. Refer to the discussion above for details on CP-206.

Group 6 (IGA) - Demonstration of Aging Management

Based on the material presented above, the following conclusions can be reached with respect to the IGA of the Group 6 components:

- The RCP seal water HXs provide a pressure-retaining boundary, and their integrity must be maintained under CLB design loading conditions.
- Intergranular attack is plausible for the RCP seal water HXs, which could lead to loss of pressure-retaining boundary integrity.
- Calvert Cliffs Technical Procedure CP-204 will mitigate the effects of IGA on the RCP seal water HX (RCS side)by maintaining primary system chemistry conditions such that impurities will be minimized, and contains acceptance criteria that ensures prompt corrective actions will be taken when adverse chemistry parameters are detected.
- Calvert Cliffs Technical Procedure CP-206 will mitigate the effects of IGA on the RCP seal water HX (CC System side) by controlling the range of specific chemical parameters, and provide action levels that ensure timely correction of adverse chemistry parameters. The procedure will also provide for the discovery of RCS leakage into the CC System by monitoring for elevated radiation levels in the CC System.
- Examinations will be performed and appropriate corrective actions will be taken if IGA is discovered.

Therefore, there is reasonable assurance that the effects of IGA on the RCP seal water HXs will be managed in order to maintain the components pressure boundary integrity under all design conditions required by the CLB during the period of extended operation.

Group 7 (SCC/IGSCC/PWSCC) - Materials and Environment

Table 4.1-3 shows that SCC, IGSCC, and PWSCC are plausible for some of the RCS device types. It should be noted that the ARDMs IGSCC and PWSCC are variations of SCC that can affect different material types, that can occur in different environments, and that can be managed by similar and/or different aging management programs. The RCS components listed below are susceptible to one or more of these ARDMs. These susceptible RCS device types, applicable ARDM(s), and their material characteristics are: [Reference 2, -CC-01/02/03/04/06, -GC-01/02/03/04/05/06, CKV-01, CV-01, ERV-01, HV-04, HX-01, MOV-01/02, PZV-01, RV-01, Attachments 4, 5, 6, Table 4.2]

<u>SCC/IGSCC/PWSCC</u>

- PZV - pressurizer - pressure, level, and temperature nozzle forgings (except Unit 2 upper pressure and level forgings - Alloy 600), pressure, level, temperature, safety/relief valve and spray nozzle safe ends (stainless steel), surge nozzle safe end (stainless steel - cast), spray and surge nozzle thermal sleeve (Alloy 600), Unit 1 heater sleeve (Nickel-plated Alloy 600**),** manway bolting (alloy steel), welds (Alloy 600); and
- -CC - charging nozzle thermal sleeve, resistance temperature detector nozzle, pressure/sample nozzle neck, safety injection thermal sleeve, surge nozzle thermal sleeve (all are Alloy 600).

- SG HX - instrument nozzles (Alloy 600), HX tubes (Alloy 600) exposed to the internal (primary side) environment of the RCS and secondary side of the SGs, primary manway studs (alloy steel).

SCC/IGSCC

- -CC - bolting studs and hex nuts (carbon steel); RPV head closure seal leakage detection piping (stainless steel), fittings (stainless steel), and welds (stainless steel); and
- -GC -bolting studs (alloy steel) and hex nuts (carbon steel).

SCC

- CKV - bolting (carbon steel);
- CV - bolting (carbon steel);
- ERV - bracket studs (alloy steel) and nuts (carbon steel);
- HV - some bodies and bonnets (CASS or forged austenitic stainless steel);
- MOV - bonnet studs and nuts (carbon steel); and
- RV - bonnet/spring/bonnet studs (carbon or alloy steel).

Alloy 600 RCS components exposed only to the RCS primary water (i.e., not SG tubes) are only susceptible to PWSCC.

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

As the interface between the primary and secondary fluids, the SG HX tubes are subjected to both the internal RCS environment and the internal SG environment.

The external RCS environment is ambient atmospheric air inside the Containment Building that is climate controlled. This environment in the Containment Building during normal operations has maximum humidity of 70% and maximum temperature of 120°F. [Reference 1, Table 9-18, Reference 29, Attachments 1, Table 1 page 13]

As a result of the actions taken due to the experience in 1989 and 1994 with minor Pressurizer Heater Sleeve leakage, BGE has replaced or scheduled near-term replacement of high-susceptibility Alloy 600 pressure boundary components. [Reference 14, Section 2] The remaining CCNPP Alloy 600 pressure boundary components are among the least susceptible to PWSCC when compared to other U.S. reactors that have performed inspections of these nozzles. [Reference 14, Section 16.2.7, Figure 6-6]

Group 7 (SCC/IGSCC/PWSCC) - Aging Mechanism Effects

Stress corrosion cracking results from the combined and synergistic interaction of a chemically-aggressive environment, susceptible material, and tensile stress (can be the result of cold working). Over long periods of time SCC occurs as the material fails by slow, environmentally-induced crack initiation and growth that may lead to eventual localized, non-ductile failure. The RCS materials susceptible to SCC are austenitic stainless steel, low-alloy steels, and nickel-based Alloy 600. Several RCS components, such as the pressurizer surge line safe ends, spray nozzle safe ends, pressurizer instrument nozzles, and pressurizer heater sleeves, are particularly susceptible to SCC. [Reference 2, PZV, Valve, Attachments 7s] Understanding of the variables that cause these effects and their interdependencies continues to improve and is the subject of ongoing research by industry worldwide and by NRC.

Intergranular SCC is the preferential dissolution of grain boundary regions with only a slight attack of the grain matrix. The IGSCC aging mechanism requires the presence of high tensile stress, material that is sensitive to attack, and the presence of corrosive anions such as oxygen, chlorides, fluorides, sulfates, and other sulfur ions.

Primary water SCC (in particular, IGSCC) is SCC that occurs in the presence of the RCS (primary side coolant) environment. The PWSCC aging mechanism has been observed in the tube roll transition region of SGs and is a problem for pressurizer instrument nozzles and heater sleeves fabricated from Alloy 600. [Reference 2, SG HX, PZV, Attachments 7s]

Experience to date indicates that cracks for PWSCC of RCS penetrations initiate first in the vicinity of penetrations and then grow axially from the penetration. The resulting cracks are short, grow slowly, grow at comparable rates axially and radially (through-wall), and result in very minimal leakage when through-wall penetration finally occurs. Therefore, safety concerns are minimal. [Reference 55]

The RCS components described above are considered susceptible to SCC, IGSCC, and PWSCC are exposed to an aggressive environment, and are placed under high tensile stresses. [Reference 2, Attachments 6s, 7s] The combined effect of these factors could result in reduction of the ability of the components to maintain the RCS pressure boundary under CLB design loading conditions. Therefore SCC, IGSCC, and PWSCC are plausible ARDMs for this group of components.

Group 7 (SCC/IGSCC/PWSCC) - Methods to Manage Aging

Mitigation: The effects of SCC, IGSCC, and PWSCC on susceptible materials in the RCS cannot be eliminated, but the effects of these ARDMs can be monitored and actions taken to mitigate the effects. Reactor coolant chemistry controls that minimize dissolved oxygen and halides and sulfur species are also believed to mitigate SCC and IGSCC susceptibility on RCS piping. Sleeving, plating, weld overlays, thermal treatment, and replacement with material less susceptible to SCC can also be used to mitigate or remedy the effects these ARDMs have on RCS components.

Discovery: Stress corrosion cracking (of all kinds) of RCS components can be discovered and monitored by inspection programs. Inspection methods and frequencies can be defined based on susceptibility of the components, and inspection results from other facilities can be used to adjust the predicted susceptibility, inspection methods, and frequency of inspection.

Given the expected axial nature of cracks, the slow growth rates, the minimal leakage that occurs once through-wall penetration does occur, and the low safety concern, periodic inspections of low-susceptibility pressure boundary penetrations for evidence of leakage is sufficient. Dedicated inspection of high-susceptibility pressure boundary and non-pressure boundary components should be considered and be timed based on expected initiation of cracks and expected propagation rates.

Detection of cracks shortly after they have initiated would permit timely repair, long before the intended function is jeopardized, and might minimize the cost and complexity of repair. Ranking models could be used to estimate SCC susceptibility and to schedule inspections based on the potential for crack initiation.

Group 7 (SCC/IGSCC/PWSCC) - Aging Management Program(s)

The CCNPP Alloy 600 Program Plan is credited with both mitigation and discovery of SCC/IGSCC for susceptible RCS piping components (except for the RPV head seal leakage detection line), SCC/IGSCC/PWSCC for susceptible pressurizer components, and SG HX instrument nozzles.

Calvert Cliffs' Alloy 600 Program Plan was developed in response to primary pressure boundary leakage at CCNPP and other plants caused by PWSCC. The CCNPP Alloy 600 Program Plan builds on CCNPP and industry experience and provides for systematic evaluation of Alloy 600 pressure boundary components in the RCS. It addresses nuclear safety concerns and identifies actions to minimize the safety and economic impact of SCC of Alloy 600 components. The program defines mitigation and discovery alternatives, as discussed below, and provides the process for considering susceptibility, safety, and economics in selecting from these alternatives. It also includes measures for monitoring industry experience and making appropriate adjustments based on this experience.

The susceptibility to SCC was evaluated for each CCNPP Alloy 600 nozzle based on ranking models developed by both Westinghouse and CE. A susceptibility index calculated from the Westinghouse model is a function of microstructure, effective stress factor, and temperature factor. The susceptibility index is used to develop a Relative Susceptibility Index, which is the susceptibility index of the component under analysis as compared to the susceptibility index of the reference/benchmark component. The reference component in this case is the CCNPP Unit 2 Pressurizer heater sleeves that developed minor leakage in 1989. The Relative Susceptibility Index is then multiplied by the actual or effective full power hours to obtain a time-dependent Relative Cumulative Susceptibility Index.

The CE model was used for the RCS Alloy 600 nozzles with inputs that were generic to all welded-tube type Alloy 600 nozzles; temperature, time in effective full power hours, and applied stress, which is based on the geometry of penetration and material yield strength. The CE model was used to calculate crack initiation probabilities as a function of effective full power hours. [Reference 14, Section 7].

The calculated susceptibility and crack initiation probability results were used to rank the nozzles and to develop recommendations for inspection, mitigation, repair and/or replacement of the nozzle(s).

[Reference 14, Section 8] The susceptibility and economic analyses are used to select from the following options available for nozzles: [Reference 14, Section 9]

- Repair/replace nozzles based on susceptibility assessment;
- Perform mitigating techniques based on susceptibility assessment;
- Continue visually inspecting each nozzle as required by the BACI Program;
- Be prepared to repair nozzles on an as-failed basis. This option requires BGE to have replacement nozzles, repair plans, and design packages ready prior to the discovery of leakage; and
- Perform augmented inspection to find non-throughwall SCC and perform repair/replacement, as necessary.

Nuclear safety, radiation exposure, and economics are considered when selecting mitigating steps or repair/replacement for nozzles susceptible to SCC. Nuclear safety considerations include whether a complete severance of the nozzle due to circumferential cracking could lead to an unisolable small break loss-of-coolant accident, whether stresses would exist that could lead to such circumferential cracking, and whether a nozzle would exhibit minor leakage before crack growth would cause rapidly increasing leakage. [Reference 14, Section 14].

The focus of this program to date has been on pressure boundary components. This is appropriate given their greater stresses and greater potential to initiate design basis events. This program plan will be modified to include RCS nozzles thermal sleeves in addition to those that form the pressure boundary. [Reference 2, Attachment 10] The SG HX tubes are specifically excluded from the scope of the Alloy 600 Program Plan. [Reference 14, Section 1.1]

Mitigation: The effects of SCC/IGSCC will be mitigated for the RCS piping (device code -CC) by CCNPP Technical Procedure CP-204. Maintaining the RCS chemistry with a minimum of impurities will aid in the prevention of these ARDMs. [Reference 2, Attachment 1] For further discussion of CP-204, refer to the Group 5 (IGA) - Aging Management Programs.

The CCNPP Alloy 600 Program Plan lists possible additional mitigation alternatives that include the following techniques: [Reference 14, Section 11]

- Shot peening - This induces compressive residual stress, slowing PWSCC initiation;
- Sleeving - A sleeve of Alloy 690 is rolled and/or welded in existing Alloy 600 sleeves;
- Weld overlay - A thin layer of welded metal with a composition equivalent to Alloy 690 is deposited over the high stress area of the Alloy 600;
- Nickel plating - This technique provides a barrier to the primary water;
- Thermal treatment - Conducted in-situ to reduce residual stress;
- RCS temperature reduction - Reduces the thermodynamic driving force for PWSCC;
- Zinc Injection - Zinc added to the primary water may slow initiation and growth of PWSCC cracks; and

- Mechanical stress improvement - Controlled plastic deformation of the nozzle(s) in a manner that creates compressive residual stresses at locations susceptible to SCC (the technique has been used extensively in Boiling Water Reactor plants on stainless steel pipe fittings, weldments, and nozzles).

If mitigation techniques are not sufficient or are unfeasible, then corrective actions are provided for nozzle(s) repair or replacement. The Alloy 600 Program Plan includes the following options to repair or replace nozzles: [Reference 14, Section 12]

- Local weld repair of defects;
- Replacement with Alloy 690 sleeves;
- Removal from service/plugging of a nozzle; or
- Encapsulate the existing nozzle in an outer nozzle bolted to the vessel to convert the nozzle into a bolted gasketed joint.

Calvert Cliffs Technical Procedure RV-78, "Reactor Vessel Flange Protection Ring Removal and Closure Head Installation," is credited with the mitigation of SCC on the RPV head seal leakage detection line. The procedure directs the user to blow the RPV head seal leakage detection line (also known as the O-ring seal leak-off line) clear of fluid with compressed air. [Reference 23, Section 6.3] Clearing the line of fluid will greatly reduce the potential for this ARDM. [Reference 2, CC06, Attachments 6] This procedure will be performed after each refueling outage. This program has been considerably upgraded through operating experience, to the point of requiring close inspection for nicks, scratches, and pitting, with documented acceptance criteria for any indications found. These upgrades have been very effective. Calvert Cliffs' reactor vessels are currently operating leak free.

Discovery: Because PWSCC of RCS penetrations is not presently a significant safety concern at CCNPP, the Alloy 600 Program Plan presently focuses its analysis on economic considerations. It assesses the relative susceptibility to PWSCC for each group of RCS nozzles and determines which are at greatest risk of crack initiation.

All RCS Alloy 600 nozzles are inspected each refueling outage for indications of leakage by the BACI Program. [Reference 33] Leakage that develops between refueling outages will be detected before significant through-wall leakage develops as a result of the Technical Specification limits on leakage. The Alloy 600 Program Plan also includes provisions for augmented inspection based on susceptibility.

Reactor Coolant System nozzles are evaluated under the Alloy 600 Program Plan based on primary and secondary factors. The primary evaluation factors for PWSCC susceptibility include: [Reference 14, Section 8]

- Operating temperature;
- Material peak stress level;
- Material heat treatment, if known;
- Number of effective full power hours; and
- Previous industry failures of same material heat.

The secondary PWSCC susceptibility factors include: [Reference 14, Section 8]

- Industry susceptibility rankings;
- Amount and type of machining/rework on a component during fabrication;
- Product form (i.e., bar, tubing, pipe);
- Whether a crevice environment exists;
- Potential for trapping contaminants due to isolation from flow circulation (stagnation);
- History of chemical excursions; and
- General susceptibility of nozzle type.

Susceptibility rankings based on predictive models cannot be used to predict the exact timing of crack initiation or progression through-wall. Primary water SCC initiation times for identical materials vary over a wide band, and predictive models take into account a limited number of parameters. Detailed study of material properties, fabrication, and service history is required to assess susceptibility of individual nozzles. However, the susceptibility models are used to allow susceptibility comparison. The CE model is used in the economic analysis to determine the optimal time for augmented inspections, but not as the basis for safety evaluations. [Reference 14, Section 7]

The susceptibility model results are used for analyzing nozzles to determine when to perform augmented inspections for crack initiation. Alternatives for augmented nozzle inspections include eddy current, dye penetrant, and ultrasonic examination. [Reference 14, Section 10]

Relevant operating experience applicable to PWSCC includes failure of purification system resin retention screens. This resulted in a resin intrusion of the Unit 1 RCS in March 1989. Resin decomposition products may contribute to cracking of sensitized Alloy 600 and the evaluation of the 1989 event concluded that prompt actions were taken to minimize the deviation and RCS temperature and to remove the resin and its decomposition products. [Reference 18]

Alloy 600 PWSCC has occurred at CCNPP and at other domestic and foreign PWRs and BGE has been a leader in industry efforts to understand and manage PWSCC. [Reference 14, Section 3] The Alloy 600 Program Plan is a relatively new program, having been initiated in 1992. Since this program achieved its present form in 1995, no pressure boundary leakage has occurred as a result of PWSCC. Some RCS components have been replaced and some have been nickel plated as a result of the program.

The Alloy 600 Program Plan includes specific provisions for monitoring industry experience and adjusting the plan accordingly. Calvert Cliffs MN-3-304, Control of the Alloy 600 Program Plan, establishes administrative controls for this program under the site procedures hierarchy. The Alloy 600 Program Plan will continue to examine pressure-boundary components susceptible to PWSCC to ensure that these components maintain their intended function required by the CLB during the period of extended operation. The program will be modified to include RCS nozzle thermal sleeves. [Reference 2, Attachments 10]

Calvert Cliffs' BACI Program is credited with the discovery of SCC/IGSCC on the external surfaces of RCS piping (pipe code -GC) studs/nuts, and SCC on RCS valve bolting. This procedure requires investigation of any boric acid leakage that is found. [Reference 2, Attachment 1] Refer to the discussion of the BACI Program in Group 2 (wear) - Aging Management Programs.

Technical Procedures STP-M-574-1/2 are credited for discovering of SCC/PWSCC on SG HX tubes. The procedure directs the user as to the sample size for tube inspection, inspection process, evaluation, and determination of tube status. Refer to the discussion of the SG Eddy Current examination program in Group 2 (wear) under Aging Management Programs.

Calvert Cliffs Administrative Procedure MN-3-110 is credited with discovering SCC on the external surfaces of RCS piping components (pipe code -CC). Visual examination (VT-2) of external surfaces are performed for the RCS components in accordance with ASME Section XI IWA-2212. The ISI Program was previously discussed in Group 2 (wear) under Aging Management Programs.

Technical Procedure FASTENER-01, "Torquing and Fastener Applications," is credited with discovering SCC on SG HX bolting studs. The procedure is used whenever studs are detensioned and retensioned on the SGs during plant refueling outages. This procedure directs the user to perform a visual inspection of the fasteners for damage and corrosion. If fasteners are acceptable they are reused, otherwise they are replaced. [Reference 56, Sections 6.2, 6.3]

Group 7 (SCC/IGSCC/PWSCC) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to SCC, IGSCC, and PWSCC of the Group 7 components:

- The pressurizer components are susceptible to SCC/IGSCC/PWSCC and provide the RCS pressure-retaining boundary. These components must maintain their integrity under CLB design loading conditions.
- The piping components listed are susceptible to SCC/IGSCC and provide the RCS pressure-retaining boundary. These components must maintain their integrity under CLB design loading conditions.
- The SG components listed are susceptible to SCC/PWSCC/IGSCC and provide the RCS pressure-retaining boundary. These components must maintain their integrity under CLB design loading conditions.
- The valve components listed are susceptible to SCC and provide the RCS pressure-retaining boundary and containment isolation function. These components must maintain their integrity under CLB design loading conditions.
- Although susceptibility to PWSCC is low relative to most other plants, PWSCC is plausible for some of the Group 7 components mentioned above, and could impair their ability to perform their intended function.
- The NRC, industry, and BGE have concluded that PWSCC axial cracking is not a safety concern and that circumferential cracking that would not be detected before it is a safety concern is not likely.

- Calvert Cliffs' Alloy 600 Program Plan provides for actions to assess SCC/PWSCC/IGSCC susceptibility and take action to mitigate, inspect, repair, or replace only Alloy 600 components based on the results. It schedules augmented inspections when crack initiation is likely.
- Calvert Cliffs' Alloy 600 Program Plan also includes provisions for monitoring and incorporating industry experience. The Alloy 600 Program Plan will be modified to include thermal sleeves installed in the RCS nozzles.
- Calvert Cliffs Technical Procedure CP-204 will mitigate the effects of SCC and IGSCC for the RCS piping components (except the RPV head seal leakage detection line) by maintaining primary system chemistry conditions such that impurities will be minimized, and contains acceptance criteria that ensures corrective actions will be taken to ensure timely correction of adverse chemistry parameters.
- Calvert Cliffs' BACI Program provides for examination of the RCS external surfaces and discovery of any SCC/IGSCC on RCS piping components and SCC on RCS valve components. The program also provides for subsequent cleanup for any boric acid leakage that is found.
- Calvert Cliffs Technical Procedure RV-78 is credited with the mitigation of SCC of the RPV head seal leakage detection line by clearing the line of stagnant fluid with compressed air.
- Calvert Cliffs Technical Procedures STP-M-574-1/2 are credited for discovering outside diameter initiated IGSCC and PWSCC on the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.
- Calvert Cliffs' ISI Program, per the requirements of ASME Section XI, is credited with the discovery of SCC and IGSCC on the external surfaces of RCS piping components. Though SCC/IGSCC cannot be completely prevented, the status of the components can be evaluated on a regular basis and corrective actions can be taken as conditions indicate SCC.
- Calvert Cliffs Technical Procedure FASTENER-01 is credited for discovering SCC on SG HX primary manway bolting studs.

Therefore, there is reasonable assurance that the effects of SCC, IGSCC, and PWSCC will be managed in order to maintain the RCS intended functions under all conditions required by the CLB during the period of extended operation.

Group 8 (thermal embrittlement) - Materials and Environment

Table 4.1-3 shows that thermal embrittlement is plausible for some of the RCS device types. These susceptible RCS device types and their material characteristics are: [Reference 2, -CC-01/05, PUMP-01, PZV-01, Attachments 4, 5, 6]

- -CC - surge pipe, surge elbows; surge nozzle safe end, shutdown cooling nozzle safe end, safety injection nozzle safe end (CASS);
- PUMP - (RCP) case and pump cover (CASS); and
- PZV - surge nozzle safe end (CASS).

The RCS internal environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1] The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control. The RCS components listed are subject to thermal and mechanical cyclic loading during RCS heat-up and pressurization.

Group 8 (thermal embrittlement) - Aging Mechanism Effects

Cast austenitic stainless steel material is susceptible to thermal embrittlement mechanisms in a high temperature environment. Thermal embrittlement is the loss of fracture toughness caused by the thermally-induced changes in the formation and distribution of alloying constituents. Ferrite-containing stainless steels are susceptible, as are materials with grain boundary segregation of impurities. [Reference 2, Valve, Attachments 7]

Fracture toughness is a measure of a material's resistance to fracture in the presence of a previously existing crack. Generally, a material is considered to have adequate fracture toughness if it can withstand loading to its design limit in the presence of detectable flaws under stated conditions of stress and temperature. The CASS thermal embrittlement mechanisms are both time and temperature dependent. The maximum rate of embrittlement for CASS occurs at 885°F ± 45°F. At lower temperatures the embrittlement rate is less, but the effects of thermal embrittlement have been observed at temperatures as low as 500°F to 650°F. [Reference 57, Section 4.2; Reference 58, Enclosure 2, Item 10]

In addition to temperature, thermal embrittlement is dependent on the CASS material alloy composition. High molybendum and carbon content contribute to thermal embrittlement susceptibility. Equally important is the casting process used to fabricate the component. Centrifugally-cast components are more resistant to thermal embrittlement than statically-cast components. [Reference 2, Attachments 7, Valve, Reference 57, Section 4.2]

For centrifugally-cast component parts with delta ferrite content below 20%, mechanical properties are not degraded significantly by the thermal embrittlement process. For statically-cast component parts with molybendum content such that it meets casting grade CF3 or CF8 limits, the 20% delta ferrite threshold also applies. However, for statically-cast component parts with molybendum content above that meeting CF3 or CF8 limits, 14% delta ferrite is the threshold below which no significant degradation due to thermal embrittlement is observed. Therefore, thermal embrittlement is potentially significant for: [Reference 57, Section 4.2]

- Centrifugally-cast component parts, with a delta ferrite content above 20%;
- Statically-cast component parts, with molybendum content meeting CF3 and CF8 limits and with a delta ferrite content above 20%; and
- Statically-cast component parts, with molybendum content exceeding CF3 and CF8 limits and with a delta ferrite content above 14%.

This aging mechanism, if unmanaged, could eventually result in a loss of material fracture toughness such that the Group 8 components may not be able to perform their intended function under CLB conditions.

Therefore, thermal embrittlement was determined to be a plausible ARDM for which the aging effects must be managed for the Group 8 components.

Group 8 (thermal embrittlement) - Methods to Manage Aging

Mitigation: There are currently no methods of mitigating the effects of thermal embrittlement other than proper material selection and by replacing susceptible components with components constructed of non-susceptible materials. Use of non-CASS components (e.g., forged stainless steel), or use of CASS components with delta ferrite content below the threshold values shown above, would make this ARDM non-plausible.

Discovery: A program that would analyze those RCS components that are susceptible to thermal embrittlement could determine if those components are able to maintain their intended function during the license renewal period. As noted in the Material and Environment section above, some of the Group 8 hand valves may have forged (i.e., not cast) stainless steel bodies/bonnets. Walkdowns can be performed to visually exam the components or gather specific manufacturer and model number information in order to determine whether the components are of forged or cast construction. For components that are determined to be of cast construction, analysis can be performed (e.g., determination of delta ferrite content) to determine if valves have adequate fracture toughness based on their material properties.

Group 8 (thermal embrittlement) - Aging Management Program(s)

Mitigation: There are no methods to prevent thermal embrittlement; therefore, there are no programs for the mitigation of this ARDM.

Discovery: A new program will be developed to manage the effects of thermal embrittlement by identifying those components that may not be able to perform their intended function due to the effects of thermal embrittlement. The CASS Evaluation Program will be based on two alternatives. The first alternative will be a delta ferrite and flaw tolerance analysis. This analysis will be performed on a case-by-case basis using actual material data and the procedure outlined in NUREG/CR-6177, Assessment of Thermal Embrittlement of Cast Stainless Steels," and NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR *[Light Water Reactor]* Systems." The flaw tolerance analysis will use the procedures from ASME Nuclear Code Case N-481. The intent of the analysis will be to determine if the respective valve has adequate fracture toughness, based on its material properties, in order to be capable of performing its pressure boundary function under CLB conditions. [Reference 2, Attachments 10]

The second alternative will be to replace the components with those that contain no CASS. The second alternative will be used if a component cannot be qualified for the license renewal term under the first alternative, or if it is more cost effective to replace rather than perform an analysis. Replacement of the component will make the ARDM as non-plausible for the respective component. [Reference 2, Attachments 10]

The corrective actions taken as part of the CASS Evaluation Program will ensure that the Group 8 components remain capable of performing their pressure boundary function under all CLB conditions.

Group 8 (thermal embrittlement) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 8 components subject to thermal embrittlement:

- The Group 8 components have the passive intended functions to maintain the RCS pressure boundary and containment isolation under CLB design loading conditions.
- Thermal embrittlement is plausible the Group 8 components which, if unmanaged, could eventually result in a loss of fracture toughness such that the Group 8 components may not be able to perform their pressure boundary function under CLB conditions.
- Calvert Cliffs' CASS Evaluation Program will perform analysis to determine if the RCS components in question have adequate fracture toughness in order to perform their pressure boundary function under CLB design loading conditions. Alternatively, the CASS Evaluation Program will replace susceptible components with components that contain no CASS, thus making the ARDM non-plausible.

Therefore, there is reasonable assurance that the effects of thermal embrittlement will be managed in order to maintain the RCS intended functions under all conditions required by the CLB during the period of extended operation.

4.1.3 Conclusion

The programs discussed for the RCS components are listed on the following table. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the RCS components will be maintained, consistent with the CLB during periods of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 4.1-4

LIST OF AGING MANAGEMENT PROGRAMS FOR THE RCS

	Program	Credited As
Existing	CCNPP "Eddy Current Exam of CCNPP Unit 1 SG," and , "Eddy Current Exam of CCNPP Unit 2 SG," (STP-M-574-1/2)	Discovery of the effects of denting (Group 1), wear (Group 2), pitting on SG tubes (Group 5), and SCC (Group 7).
Existing	CCNPP "Pressurizer Manway Cover Removal and Installation," (RCS-10)	Discovery of the effects of wear (Group 2) on pressurizer studs, nuts, and seating surfaces.
Existing	CCNPP "SG Secondary Manway Cover Removal and Installation" (SG-1/2); "Steam Generator Secondary Handhole Cover Removal" (SG-5); and "Steam Generator Secondary External Handhole Cover Installation" (SG-6)	Discovery of the effects of wear (Group 2) on SG closure surfaces.
Existing	CCNPP "RCS Leakage Evaluation" (STP-O-27-1/2)	Discovery of the effects of wear (Group 2).
Existing	CCNPP "Use of Operating Experience and the Nuclear Hotline" (NS-1-100)	Discovery of the effects of wear (Group 2) on RCP tube-in-tube seal water HX through a continuing review of industry experience.
Existing	CCNPP "SG Primary Manway Cover Removal and Installation" (SG-20)	Discovery of the effects of wear (Group 2) and general corrosion (Group 5) on the primary side of the SG manway and seating surfaces.
Existing	CCNPP "Inservice Inspection of ASME Section XI Components" (MN-3-110)	Discovery, per ASME XI, of the effects of wear (Group 2), erosion corrosion (Group 3), general and galvanic corrosion (Group 5), SCC and IGSCC (Group 7) on those RCS components susceptible to these ARDMs.
Existing	CCNPP BACI Program (MN-3-301)	Discovery and mitigation of the effects of wear (Group 2), erosion (Group 3) galvanic/general corrosion (Group 5), and SCC/IGSCC (Group 7).
Existing	CCNPP "Specifications and Surveillance for Component Cooling/Service Water System" (CP-206)	Mitigation of the effects of IGA (Group 6) on the RCP seal water HXs.

	Program	Credited As
Existing	CCNPP "Specification and Surveillance Primary Systems" (CP-204)	Mitigation of the effects of IGA (Group 6) and SCC, IGSCC, and PWSCC (Group 7) on RCS components.
Existing	CCNPP Torquing and Fastener Applications (FASTENER-01)	Discovery of the effects of SCC (Group 7) on RCS fasteners. Those fasteners that are non-acceptable are replaced.
Existing	CCNPP RV-78, "Reactor Vessel Flange Protection Ring Removal and Closure Head Installation"	Mitigation of the effects of SCC (Group 7) on the RPV head closure seal leakage detection line.
Modified	CCNPP FMP	Discovery of the effects of low-cycle fatigue (Group 4). The FMP will be modified to perform an engineering evaluation for the RCPs, MOVs, and pressurizer RVs to ensure that the components are bounded by existing critical locations and controlling transients. If they are not bounded they will be added to the FMP.
Modified	CCNPP Alloy 600 Program	Discovery and mitigation of the effects of SCC, IGSCC, and PWSCC (Group 7), and will be modified to include the RCS nozzle thermal sleeves.
New	CASS Evaluation Program	Discovery and management of the effects of thermal embrittlement (Group 8).

4.1.4 REFERENCES

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5. Letter from Mr. R. M. Douglass (BGE) to Mr. B. H. Grier (NRC), dated May 17, 1978, CCNPP 30-Day Report for Licensee Event Report 317 78-22/3L
6. Letter from Mr. L. B. Russell (BGE) to Mr. B. H. Grier (NRC), dated January 24, 1979, CCNPP 30-Day Report for Licensee Event Report 318 79-01/3L
7. Letter from Mr. L. B. Russell (BGE) to Mr. B. H. Grier (NRC), dated February 1, 1979, CCNPP 14-Day Report for Licensee Event Report 318 79-03/1T
8. Letter from Mr. L. B. Russell (BGE) to Mr. B. H. Grier (NRC), dated May 30, 1980, CCNPP 30-Day Report for Licensee Event Report 317 80-24/3L
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15. Letter from Mr. P. E. Katz (BGE) to NRC Document Control Desk, dated August 30, 1996, "CCNPP Unit 1 Steam Generator Tube Inspection Results"
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24. CCNPP Drawing 60729SH0001, "RCS," Revision 61
25. "CCNPP Component Level ITLR Screening Results, RCS System 64," Revision 4, October 17, 1996
26. CCNPP Drawing 92767SH-EB-1, "M-601 Piping Class Sheets," Revision 21, October 19, 1994
27. CCNPP Technical Procedure STP-M-574-1, "Eddy Current Exam of CCNPP Unit 1 SG," Revision 6, March 12, 1993
28. CCNPP Technical Procedure SG-5, "SG Secondary External Handhole Cover Installation," Revision 7, December 23, 1996
29. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
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31. CCNPP Administrative Procedure MN-3-110 "Inservice Inspection of ASME Section XI Components," Revision 2, July 2, 1996
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48. CCNPP Engineering Standard ES-020, “Specialty Input Screens for the Engineering Service Process,” Revision 1, May 1, 1996

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55. NRC Generic Letter 97-01, “Degradation of Control Rod Drive Mechanism Nozzle and other Vessel Closure Head Penetrations,” April 1, 1997

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4.2 Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Reactor Pressure Vessels (RPVs) and Control Element Drive Mechanisms (CEDMs)/Electrical System, including the Reactor Vessel Level Monitoring System (RVLMS). The RPVs and CEDMs/Electrical System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

4.2.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools that capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to an aging management review (AMR) begins with a listing of passive intended functions, and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to an AMR either in this report or another report.

Section 4.2.1.1 presents the results of the system level scoping, 4.2.1.2 the results of the component level scoping, and 4.2.1.3 the results of scoping to determine components subject to an AMR.

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently assigned cognizant CCNPP personnel.

4.2.1.1 System Level Scoping

This section begins with a description of the system, which includes the boundaries of the system as it was scoped. The CEDMs/Electrical System section also contains the RVLMS description. The intended functions of each system are listed and are used to define what portions of the system are within the scope for license renewal.

System Description/Conceptual Boundary

The CCNPP Unit 1 and Unit 2 RPVs are major parts of each Reactor Coolant System (RCS). Each RCS has one RPV, one pressurizer, two steam generators, two reactor coolant loops, and four reactor coolant pumps. [Reference 1, Section 1.1] The RPVs are comprised of a removable head with multiple penetrations, four primary coolant inlet nozzles, two primary coolant outlet nozzles, upper, intermediate and lower shell courses, bottom head and vessel supports. Each vessel is approximately 503-3/4-inches high, with an inside diameter of 172 inches, and is an all-welded, manganese molybdenum steel plate and forging construction. [Reference 2, Section 1.1.1] The RPV is supported vertically and horizontally by three pads welded to the underside of the RPV primary nozzles. Each RPV support consists of a support foot welded to the primary nozzle; a socket bolted to the support foot (with cap screws); and a sliding bearing whose spherical crown fits into the socket and whose flat side sliding surface rests on a base plate. [Reference 1, Section 4.1.3] Figure 4-2 in the CCNPP Updated Final Safety Analysis Report (UFSAR) has a drawing of the RPVs. [Reference 1, Section 4.1.3.1]

Each RPV contains the reactor vessel internals (RVI) and associated reactor core (See Section 4.3 of the BGE LRA for the RVI IPA results). The reactor is controlled by a combination of a chemical shim (dissolved boric acid), and control element assemblies (CEAs) which are made of a solid boron carbide neutron absorber. The CEAs (i.e., four tubes in a square matrix plus a central tube) are connected together at their tops by a yoke, which is, in turn, connected to the CEDM extension shaft (there are some CEDMs that have two yokes attached). The CEDMs are designed to permit rapid insertion of the CEAs in the reactor core by gravity. [Reference 1, Section 1.2.3, 1.2.7.2]

The CEDMs are magnetic jack-type drives capable of withdrawing, inserting, holding, or tripping a CEA from any point within their 137-inch stroke. Originally, 65 CEDMs were mounted on flanged nozzles on top of the reactor closure head. Eight of those CEDMs were connected to partial length CEAs, which have been subsequently removed. [Reference 1, Section 3.3.4.1] Two of the eight CEDMs have been modified to house RVLMS probes. [Reference 2, Section 1.1.1] The CEDM housings comprise the motor assembly, the motor housing assembly, the coil stack assembly, the upper pressure housing assembly, the shroud and conduit assembly, the reed switch assembly, and the drive shaft. [Reference 2, Section 1.1.3] The CEDM pressure housings are an extension of the reactor vessel, providing a part of the reactor coolant boundary, and are, therefore, designed to meet the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section III, Nuclear Vessels. [Reference 1, Section 3.2.3.6] Refer to Figure 3.3-15 in the UFSAR for a drawing of the CEDMs.

The RVLMS housings consist of only a motor housing assembly, an upper pressure housing assembly (modified from the CEDM design), the shroud, the flange adapter assembly, and a Heated Junction Thermocouple (HJTC) probe assembly. [Reference 2, Section 1.1.3] This system is capable of providing the plant operator with the information needed to assess void formation in the reactor vessel head region, and the trend of liquid level in the reactor vessel plenum. The HJTC system is composed of two redundant channels, each powered from separate, reliable Class 1E sources. [Reference 1, Section 7.5.9.2]

System Operating Experience

The following are operating experiences related to the RPVs and CEDMs with the potential for affecting the intended functions of the components or systems.

Reactor Coolant Pump (RCP) Suction Deflector Failures

The 1988 and 1996 failures of the RCP suction deflector bolting at CCNPP are examples of changes to the RPV operating environment that could have had an effect on the ability of the RPV to perform its intended functions. A portion of the failed bolt was not recovered at the pump in each case, and was assumed to be lodged in the RPV on the cladding and near the downcomer. Combustion Engineering (CE) analyzed the 1988 failure and the potential impact to the Unit 2 RPV cladding of leaving the bolt until the 1989 refueling outage. CENC-1849, "Evaluation of Reactor Vessel Potential Wear of Bottom Head Clad Due to Loose Bolt," documents the analysis results. The evaluation determined there will be no unacceptable impact to the clad. The reactor core was off-loaded, the RVI removed, and bolt fragments were recovered during the 1989 refueling outage. Calvert Cliffs' Corrective Action Program results document the root cause analysis and the potential impact to the clad for the 1996 failure. The next scheduled RPV Inservice Inspection (ISI) will examine the affected area and recover the fasteners from the 1996 failure. [References 3 and 4]

RPV Closure Head Stud Overtensioning

On several occasions, closure studs were overtensioned during RPV head boltup, which could have had an effect on the RPV's intended function. Baltimore Gas and Electric Company's Design Engineering and CE evaluated each situation and determined that the studs and flanges were undamaged. For example, CR-9417-CSE92-1108, "Evaluation of a Reactor Vessel Closure Head Stud Elongation for BGE Calvert Cliffs," documents CE's evaluation that one of these incidents did not change the RPV's ability to perform the intended functions. Baltimore Gas and Electric Company's Design Engineering reviewed and accepted this evaluation. [Reference 5]

RCS Pressure Boundary Leakage

Calvert Cliffs experienced primary pressure boundary leakage of Alloy 600 Components caused by primary water stress corrosion cracking (PWSCC). Calvert Cliffs has a total of 244 Alloy 600 penetrations in the Unit 1 RCS, and 126 remaining in the Unit 2 RCS (120 pressurizer heater sleeves were replaced with Alloy 690 in 1989-1990). In 1989, a pressurizer vapor space instrument nozzle was found leaking, which led to the replacement of all four of the Unit 2 pressurizer vapor space nozzles. Also in 1989, 22 heater sleeves were found leaking, which resulted in the subsequent replacement of 119 heater sleeves with Alloy 690. During the 1994 Unit 1 refueling outage, two heater sleeves were found leaking, resulting in the nickel plating of the remaining 118 heater sleeves during the outage. The replacement and repair of the heater sleeves corrected the leakage problems and also contributed to the development of the CCNPP Alloy 600 Program Plan. Calvert Cliffs determined that the pressurizer heater sleeve leakage events were attributed to PWSCC, driven by residual stress created by cold working during fabrication. [Reference 6, Sections 1, 2, 3, 19] The Alloy 600 Program Plan is also important for RPVs and CEDMs/Electrical System components.

RCS Resin Intrusion

Calvert Cliffs Unit 1 had a resin intrusion in March 1989, and Unit 2 suffered a resin intrusion in January 1983, due to a failed outlet retention element of the ion exchanger in the purification system. The effect on the RPVs was evaluated at the time of the intrusions and found to be acceptable. Resin intrusions are a potential issue since resin decomposition products may contribute to cracking of sensitized Alloy 600. The Unit 1 resin intrusion event caused high sulfate levels in the RCS, which subsequently resulted in the Unit being shut down. The sulfate concentration in the RCS was evaluated by CE and BGE. The evaluation concluded that the potential increase for stress corrosion cracking (SCC) was insignificant. [Reference 7]

RPV Head Flange Corrosion

During the outage in 1990, corrosion (rust) was found on the Unit 2 RPV upper head, flange, and stud holes. The corrosion on the RPV upper head, flange, and stud holes was due to moisture collecting under a tent in the Containment Building. The corrosion was removed and the stud holes cleaned. An analysis determined the maximum allowed stud hole diameter. Measurements by BGE showed that the RPV flange was within its design tolerances, and that the RPV flange stud hole diameters were less than the maximum allowed diameter.

Unintentional Inclusion of Slag Stringer in RPV

The unintentional inclusion of a small slag stringer in a Unit 1 RPV weld is an example of a fabrication flaw with potential to impact the ability of the RPV to perform its intended functions. The slag stringer was identified during pre-operational ultrasonic technique examinations. Southwest Research Institute evaluated the stringer and found it to be within acceptable code limits. The Southwest Research Institute report, "Preliminary Ultrasonic Examination of Weld Seams in the Calvert Cliffs Unit 1 Nuclear Reactor Vessel," contains the examination and evaluation results. During the first Unit 1 RPV ISI, CCNPP performed enhanced ultrasonic technique examinations of the stringer to determine the acceptability of the flaw. The flaw was still within the acceptance limits of ASME Section XI. The 1986 Inservice Examination Report documents the results of this examination. [References 8 and 9]

RPV Surveillance Program

To address neutron induced embrittlement of the RPV materials, the CCNPP Comprehensive Reactor Vessel Surveillance Program (CRVSP) was formed. The CRVSP evaluates testing on RPV surveillance materials to address chemistry variability issues, and uses the surveillance and other research results to support industry development of measuring fracture toughness for surveillance materials. To increase the data on material properties for the CCNPP RPVs, BGE installed ex-vessel dosimetry, a supplemental CCNPP Unit 1 surveillance capsule, and purchased portions of the Shoreham RPV. The CRVSP also incorporates test results of the surveillance capsules from other power plants with similar material chemistry for analysis of CCNPP RPV fracture toughness. [Reference 10]

Low Temperature Overpressure Protection (LTOP)

The original CCNPP design did not require automatic protection from low temperature overpressurization events. Early industry overpressurization incidents resulted in regulatory changes that required greater protection, including automatic actions. To compensate for the limited pressure relieving capacity provided by the original design, BGE made commitments to the NRC, in July 1977, to enact certain administrative controls during low temperature operations. During 1989 to 1990, CCNPP re-evaluated all docketed commitments and incorporated them into site procedures. The LTOP Controls Report captures the LTOP design basis requirements and the administrative controls, including procedural controls. Calvert Cliffs' EN-1-214, "Low Temperature Overpressure Protection," is the controlling procedure for the preparation, review, and updating of the LTOP Controls Report. EN-1-214 also contains the requirements for periodic audits of LTOP controls. [References 11 and 12]

In summary, these events demonstrate that CCNPP has and will continue to address and perform corrective actions, as required, so that the RPVs and CEDMs/Electrical System components are capable of performing their intended function under the current licensing basis (CLB) conditions during the period of extended operation.

System Interfaces

The CEDM components under review in this report interface with the RCS. The RPV is a major component of the RCS. The RCS is within scope for license renewal and described in Section 4.1 of BGE's LRA. The RPVs and CEDMs/Electrical System also interfaces with the RVI (Section 4.3 of BGE's LRA), Cranes and Fuel Handling (Section 3.2 of BGE's LRA), and the containment interior structures (in Structures report, Section 3.3 of BGE's LRA). The leakage monitoring instrument line that is attached to the leakage monitoring tube from the RPV is another interface that is within scope for license renewal (in RCS report, Section 4.1 of BGE's LRA).

The interior surfaces of the RPVs and CEDMs are completely wetted by the RCS environment. Section 4.1 of BGE's LRA credits primary chemistry control as an aging management program to manage plausible aging of components in the RCS. Because this chemistry program is credited for the RCS, and because the interior surfaces of the RPVs and CEDMs are totally wetted from the RCS environment, the demonstration of the primary chemistry control program as an aging management program is not repeated in this section. Instead, the aging evaluation for the internal surfaces of the RPVs and CEDMs credits the chemically-treated and controlled, demineralized water environment provided by the RCS as an initial condition of this evaluation.

System Scoping Results

The RPVs, RVLMS, and system components are within scope for license renewal based on 10 CFR 54.4(a). In accordance with Section 4.1.1 of the CCNPP IPA Methodology, a detailed list of system intended functions was determined based on the requirements of 10 CFR 54.4(a)(1) and (2): [Reference 2, Section 1.1.4]

- To vent the RCS when natural circulation flow has been disrupted or blocked by accumulation of non-condensable gases;
- To provide reactor vessel coolant inventory level indication;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To provide structural support for the fuel assemblies, CEAs, and incore instrumentation (ICI) so that they maintain the configuration and flow distribution characteristics assumed in the CCNPP UFSAR Chapter 14 analyses.

The CEDMs and Electrical System components are within scope for license renewal based on 10 CFR 54.4(a). In accordance with Section 4.1.1 of the CCNPP IPA Methodology, a detailed list of system intended functions was determined based on the requirements of 10 CFR 54.4(a)(1) and (2): [Reference 13, Table 1]

- Provide a pressure retaining boundary for the RCS; and
- To provide rapid shutdown of the reactor.

The following CEDM intended functions were determined based on the requirements of 10 CFR 54.4(a)(3): [Reference 13, Table 1]

- For fire protection (§50.48) - Interrupt CEDM Motor Generator set output power to ensure safe shutdown in the event of a severe fire.
- For anticipated transient without scram (§50.62) - Initiate reactor trip by interrupting power to the CEDMs upon Diversified Scram System signal.
- For station blackout (§50.63) -Trip reactor to provide for rapid shutdown of the reactor.

The design parameters for each of the major RCS components are given in Section 4.1.3 of the CCNPP UFSAR. The RCS (and thus RPVs) is designated a Class I system for seismic design, and is designed for the criteria for load combinations and stress that are presented in Table 4-8 and design Codes, as listed in Table 4-9 of CCNPP UFSAR Section 4.1.3. The regulations listed in 10 CFR 54.4(a)(3) do not necessarily require nuclear safety grade components in order to respond to the requirements of the regulations. The components of the CEDMs that have intended functions listed above are subject to the applicable loading conditions identified in UFSAR Section 4.1.3, Table 4-8.

4.2.1.2 Component Level Scoping

Each RPV is identified by a single unique equipment identifier; therefore, the component level scoping for the RCS identified those two components as within scope for license renewal. These represent a single device type and equipment type. The RCS scoping also identified the RVLMS probes as within scope of license renewal; however, since these are directly related to the CEDM evaluation, they are addressed in this section of the BGE LRA. Each CEDM is also assigned a single unique equipment identifier; therefore, the component level scoping for the CEDMs/Electrical System identified 130 CEDMs. [Reference 2, Section 2.2] Based on the intended functions listed above, the portions of the RPVs and CEDMs/Electrical System that are within scope for license renewal include the following eight device types: [Reference 2, Table 2-1]

	Device Description	Device Code
1.	Control Element Drive Mechanism	(CEDM)
2.	Pressure Vessel	(PZV)
3.	480 VAC Motor	(MB)
4.	125/250 VDC Motor	(MD)
5.	Electrical Panel	(PNL)
6.	Test Point (RVLMS Probe)	(TP)
7.	Control Element Assembly	(CEA)
8.	Load Contactor	(CONT)

4.2.1.3 Components Subject to Aging Management Review

This section describes the components of the RPVs and CEDMs/Electrical System which are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the component types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or evaluated for aging management in this report.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following RPV functions were determined to be passive. [Reference 2, Table 3-1a]

- To maintain the pressure boundary of the system (liquid and/or gas); and
- To provide structural support for the fuel assemblies, CEAs, and ICI so that they maintain the configuration and flow distribution characteristics assumed in the UFSAR Chapter 14 analyses.

Similarly, the following CEDMs/Electrical System function was determined to be passive. [Reference 2, Table 3-1b]

- Provide pressure boundary for the reactor coolant system.

The components of the RPVs and CEDMs/Electrical System, and their supports, were reviewed, and all of the components that have at least one intended function were identified. Of the eight device types identified within scope for license renewal: [Reference 2, Table 3-2]

- 480 VAC Motors, 125/250 VDC Motors, Control Element Assemblies, and Load Contactors are only associated with active functions.
- Electrical panels in the CEDMs/Electrical System are evaluated for the effects of aging in the Electrical Panels Commodity Evaluation in Section 6.2 of BGE's LRA.
- Electrical components and cables associated with components in the system are evaluated for the effects of aging in the Environmental Qualification Commodity Evaluation in Section 6.3 of BGE's LRA.

The three remaining device types, listed in Table 4.2-1, are subject to an AMR, and are the subject of the remainder of this report.

TABLE 4.2-1

RPVs AND CEDMs / ELECTRICAL SYSTEM
DEVICE TYPES REQUIRING AMR

RPV (PZV)
CEDM
RVLMS Test Point (TP)

Other RPV Subcomponent Intended Functions

The RCS System Level Scoping identified the intended functions of the RPVs, and the CEDMs/Electrical System Component Level scoping identified those of the CEDMs/Electrical System. These results were presented in Section 4.2.1.1 under System Scoping Results. Using the CCNPP IPA Methodology of Section 6.2.2, Structures and Components Grouping, the RPVs were further subdivided into individual subcomponents. These groups of RPV subcomponents were found to have additional passive intended functions beyond that of RCS pressure-retaining boundary. These additional passive intended RPV functions are addressed throughout this section. Some of the following RPV passive functions contribute to the RVIs' performance of its intended functions. The additional passive intended functions determined in accordance with CCNPP IPA Methodology Section 6.2.2 are listed below: [Reference 2, RPV, Attachment 4]

- Support RPV, restrict lateral vessel movement, allow vessel thermal expansion and contraction [Vessel Supports (i.e., sliding plate, plate steel, anchor bolts, cooling jacket, sockets, cap screws, shim and base plates, and support pads)];
- Monitor leakage from between the O-rings [Leakage Monitoring Tube];
- Minimize thermal stress to the CEDM [CEDM Thermal Sleeves];
- Reduce core inlet flow inequalities and prevent formation of large vortices [Flow Skirt];
- Prevent excessive core displacement under specified accident conditions [Core Stop Lugs];
- Limit flow-induced vibrations in the core support barrel [Core Stabilizing Lugs, Bolts, and Shims, Snubbers Spacer Blocks and Capscrews]; and
- Support surveillance capsules, which provide supporting information to predict the embrittlement condition of the RPV [Surveillance Capsule Holders].

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to an AMR.

4.2.2 Aging Management

The potential ARDMs for the RPVs and CEDMs/Electrical System components are listed in Table 4.2-2. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate column. Those potential ARDMs, which were considered in the analysis to not be plausible, are marked with an (x) in the Not Plausible For System Column. [Reference 2, Tables 4-1 and 4-4] The device types listed in Table 4.2-2 are those previously identified in Table 4.2-1 as passive and long-lived. The device types not included in Table 4.2-2 were previously dispositioned with the CCNPP IPA Methodology as performing an active function and/or addressed in commodity evaluations. For efficiency in presenting the results of these evaluations in this report, the components here are grouped together based on similar ARDMs. [Reference 2, Section 4.4]

TABLE 4.2-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE RPVs AND CEDMs / ELECTRICAL SYSTEM

Potential ARDMs	Device Types			Not Plausible for System
	PZV (RPV)	TP (RVLMS)	CEDM	
Corrosion Fatigue				x
Erosion				x
Fatigue (Group 3)	✓(a)	✓	✓	
General Corrosion (Group 1)	✓(b)			
Hydrogen Embrittlement				x
Neutron Embrittlement (Group 4)	✓(c)			
Stress Corrosion Cracking (Group 5)	✓(d)			
Stress Relaxation				x
Wear (Group 2)	✓(e)	✓(e)	✓(e)	

✓ Indicates plausible ARDM determination.

( ) Indicates that not all components of a device type are affected by the ARDM. The notes below clarify the exceptions. [Reference 2, Attachments 4, 5, and 6]

(a) All RPV components except for vessel supports (sliding bearing, plate steel, anchor bolts, cooling jacket, sockets, capscrews, shim and base plates, and support pads) and snubber spacer blocks and capscrews.

(b) Only the unclad external surfaces of the RPV upper/lower head and cylindrical shell plates and their welds, nozzle welds; RPV and closure head flanges, inlet and outlet nozzles, and nozzle safe ends; RPV closure head studs, nuts, and washers; RPV vessel supports (plate steel, anchor bolts, cooling jacket, sockets, shim and base plates, and support pads).

(c) Only the vessel plates and welds of the lower shell, intermediate shell, and lower portion of the nozzle shell courses.

(d) Only the RPV leakage monitoring tube; ICI tube nozzles, Vent pipe, and CEDM nozzles; flow skirt; core stop lugs; core stabilizing lugs; surveillance capsule holders; and RPV supports anchor bolts.

(e) Only the vessel flanges (threaded stud holes); RPV closure head studs, nuts, and washers; core stabilizing lugs and snubber spacer blocks; RPV ICI tube flanges including their bolts and nuts; and RVLMS blind flange adapter hub vent plug and flange nut, Grayloc clamp set, studs, nuts and seal plug drive nut; CEDM ball seal housing; and CEDM and RVLMS upper housing assembly steel balls.

The following discussions present information on plausible ARDMs. The discussions are grouped by ARDM and address the materials and environment pertinent to the ARDM, the aging effects for each plausible ARDM, the device types that are affected by each, the methods to manage aging, the aging management program(s), and the aging management demonstration. The groups addressed are:

Group 1 - general corrosion;

Group 2 - wear;

Group 3 - fatigue;

Group 4 - neutron embrittlement; and

Group 5 - stress corrosion cracking.

Group 1 (general corrosion) - Materials and Environment

Table 4.2-2 shows that corrosion is plausible for only specific RPV components. This ARDM affects the unclad external surfaces of carbon steel RPV components that could be wetted by boric acid or component cooling water. The group of subcomponents potentially affected and material characteristics are: [Reference 2, RPV Attachments 4, 5, and 6]

- RPV upper/lower head/cylindrical shell plates (SA-533 Grade B Class 1 with stainless steel cladding on internal surfaces) and their welds and stainless steel clad;
- RPV and closure head flanges, inlet and outlet nozzles, nozzle safe ends (SA-508-64 Class II with stainless steel cladding on internal surfaces);
- RPV closure head studs, nuts, and washers (A-540 Grade 23 Class III and A-540 Grade 24 Class III),
- RPV supports: plate steel (A-302 Grade B), anchor bolts (A-354 Grade B6), cooling jacket (A-106 Grade B), sockets (A-536), shims and base plates (ANSI 4140), and support pads (SA-508-64); and
- RPV nozzle welds with stainless steel cladding on internal surfaces.

The internal environment of the RPVs and CEDMs is that of the RCS, which contains water at an operating pressure of approximately 2250 psia. Normal RCS operating temperatures are approximately 548°F in the cold leg and 599.4°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The external environment is ambient atmospheric air inside the Containment Building that is climate controlled. This environment in the Containment Building during normal operations has maximum humidity of 70% and maximum temperature of 120°F. [Reference 1, Table 9-18] The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

Group 1 (general corrosion) - Aging Mechanism Effects

Corrosion is degradation that results in wall thinning due to oxidation of low alloy and high alloy ferritic steel components. Forms of general corrosion include uniform attack, pitting, and intergranular attack. [Reference 2, Attachment 7]

General corrosion is a concern for RPV low alloy and high alloy ferritic steel subcomponents listed above. Therefore, corrosion is a plausible ARDM for the RPV steel subcomponents. Corrosion is concern due to the boric acid concentration of the RCS fluid. The particular concern is potential leakage onto external component surfaces from this RCS fluid. There has also been corrosion observed in the O-ring grooves of the RPV head due to a high local dissolved oxygen content. [Reference 2, RPV, Attachment 6, Code T]

If left unmitigated in the long-term, corrosion could eventually result in sufficient wall thinning from localized pitting, and/or general area material loss to cause failure of the pressure-retaining capability under CLB design loading conditions.

Group 1 (general corrosion) - Methods to Manage Aging

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of the carbon steel surfaces of the RPV metal components to an aggressive chemical environment. Stainless steel cladding on the interior of the RPV components minimizes the effects of general corrosion on the interior surfaces exposed to reactor coolant. However, mitigation of corrosion on the exterior surfaces of the RPV requires the prevention of RCS leakage from the RPV pressure boundary, and the removal of any boric acid residue from exterior RPV surfaces.

Discovery: The effects of corrosion on the RPV pressure boundary can be discovered through a program of visual inspections on the RPV areas susceptible to this ARDM. Inspection of the areas around the RPVs could identify leakage occurring, and result in corrective actions being taken before corrosion could degrade the RPV's intended function. The inspections must be performed on a frequency that is sufficient to ensure that the minimum vessel thickness requirements will be met until the next inspection is performed.

Group 1 (general corrosion) - Aging Management Program(s)

Mitigation: The CCNPP "Boric Acid Corrosion Inspection Program," (MN-3-301) can mitigate the effects of boric acid corrosion through discovery of leakage of RPVs and CEDMs/Electrical System components, and removal of any boric acid residue that is found. Removal of any boric acid leakage from component surfaces mitigates the effects of this substance on these surfaces. [Reference 2, Attachment 8, General Corrosion]

Discovery: The CCNPP ISI Program is credited with discovering general corrosion on the RPV supports and anchor bolts. These RPV supports and anchor bolts will be visually examined, as defined in IWF-2500 of the ASME Code Section XI and acceptance criteria contained in IWF-3410. The purpose of the ISI Program is to control the methods and actions for ensuring the structural and pressure-retaining integrity of safety-related nuclear power plant components, in accordance with the rules of ASME Section XI. [Reference 14, Section 3.0D] The Long Term Plan uses the requirements of Section XI of the ASME Code, 1983 Edition through Summer 1983 Addenda, and is subject to periodic update per 10 CFR 50.55a. [Reference 15, Section 1.2.1]

The scope of the existing ISI Program for the RPVs and CEDMs includes examination and inspection of components identified in ASME Section XI, Subsection IWB. [Reference 16, Section 1.2A] The ISI Program is performed to meet the requirements of references identified in Section 1.2A of Reference 16.

An extensive list of the developmental and performance references for the existing ISI Program is provided in Section 2.0 of Reference 16.

Inservice inspection requirements in ASME Section XI, as implemented by the existing ISI Program, provide for visual examination of accessible surfaces of reactor vessel components. [Reference 17, Table IWB-2500-1] For visual examination of the RPV supports and anchor bolts, ASME Section XI requires determining the general mechanical and structural conditions of the components for wear, and loss of integrity at bolted connections. Examinations may require, as applicable, determination of structural integrity, measurement of clearances, detection of physical displacements, structural adequacy of supporting elements, connections between load-carrying structural members, and tightness of bolting. [Reference 17, IWA-2213 Visual Examination VT-3]

If any abnormal condition is identified, the ASME Code provides requirements for the timely correction of the condition. [Reference 17, IWA-4130 Repair Program] Visual inspections can readily identify damage to the RPV supports and anchor bolts, such as would be caused by general corrosion, wear, and other aging mechanisms. The corrective actions taken will ensure that the RPV supports and anchor bolts remain capable of performing their intended functions under all CLB conditions.

The ISI Program is subject to internal and independent assessments, and is recognized through these assessments as performing highly effective examinations and aggressively pursuing continuous improvements. Baltimore Gas and Electric Company monitors industry initiatives and trends in the area of ISI and non-destructive examination, and plays a leadership role in developing, analyzing, and advancing non-destructive examination and ISI methods. The program is also subject to frequent external assessments by the Institute for Nuclear Power Operations, NRC, and others.

Operating experience relative to the ISI Program at CCNPP has been such that no site-specific problems or events have required changes or adjustments. The program has been effective in its function of performing examinations required by ASME Section XI.

Two design improvements have been made to the reactor vessel to facilitate the ISI Program. First, pads have been placed on the outside of the vessel to function as location benchmarks for ultrasonic inspection. Second, additional room has been provided between the nozzle piping and surrounding concrete to allow inspection of the piping. [Reference 1, Section 4.1.5.5]

The RPV support components should not be subject to an aggressive environment. However, the supports are normally not accessible, and there is the potential for boric acid leakage and component cooling water (which cools the supports) leakage creating an adverse environment. Therefore, the supports are examined on a regular basis (per ASME Section XI) to ensure they are not subject to such an environment. [Reference 2, Attachment 6, Code T]

Discovery of boric acid leakage is performed by MN-3-301, Maintenance Procedures RV-22, "RPV O-Ring Replacement," and RV-62, "RPV Stud, Nut, and Washer Cleaning and Inspection." These programs and procedures require the visual inspection of RPVs and CEDMs/Electrical System components for boric acid leakage. MN-3-301 requires investigation of any leakage that is found, and implements the visual examination of external surfaces with the system under normal operating pressure (i.e., VT-2) for the RPVs and CEDMs/Electrical System components in accordance with ASME Section XI IWA-2212.

The Maintenance Procedures supplement the Boric Acid Corrosion Inspection Program through inspections of their respective RPV components. [Reference 2, Attachment 8, General Corrosion]

The basis for the establishment of the program is GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The ISI Program controls examination and test methods and actions to minimize the loss of structural and pressure-retaining integrity of RCS pressure boundary components due to boric acid corrosion. [Reference 16, Section 3.0.C; Reference 18, Section 1.1]

The scope of the program is threefold: (1) It provides examination locations where leakage may cause degradation of the primary pressure boundary by boric acid corrosion; (2) provides examination requirements and methods for the detection of leaks; and (3) provides the responsibilities for initiating engineering evaluations and the subsequent proposed corrective actions. [Reference 18, Section 1.2]

Upon reaching reactor shutdown, ISI personnel are required to perform a containment walkdown inspection (VT-2) as soon as possible after attaining hot standby condition to identify and quantify any leakage found in specific areas of the Containment Building. A second ISI walkdown is performed prior to plant startup. The ISI must ensure that all components that are the subject of Issue Reports (IRs), where boric acid leakage has been found, are examined in accordance with the requirements of this program. [Reference 18, Sections 5.1 and 5.2] Calvert Cliffs procedure QL-2-100, "Issue Reporting and Assessment," defines requirements for initiating, reviewing, and processing IRs, and resolution of issues. Issue reports are generated to document and resolve process and equipment deficiencies and nonconformances. [Reference 19, Sections 1.1 and 1.2]

Under the Boric Acid Corrosion Inspection Program, the VT-2 walkdown examinations must be performed in accordance with ASME XI, IWA-2212. The VT-2 walkdown examinations must include the accessible, external, exposed surfaces of pressure-retaining, noninsulated components; floor areas or equipment surfaces located underneath noninsulated components; vertical surfaces of insulation at the lowest elevation where leakage may be detected, and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas where water may be channeled for insulated components whose external insulation surfaces are inaccessible for direct examination; and for discoloration or residue on any surface for evidence of boric acid accumulation. Any leakage detected must be reported on an IR for corrosion degradation assessment. [Reference 18, Section 5.2]

Issue reports that have been written in accordance with this program are required to address: (1) The removal of the boric acid residue; and (2) The inspection of the affected components for general corrosion. If general corrosion is found on a component, the IR resolution provides an evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 18, Section 5.3]

In addition to the Boric Acid Corrosion Inspection Program, credit is also taken for CCNPP Procedure RV-62 for the discovery of general corrosion. RV-62 specifies the procedural steps and materials to be used in the cleaning and inspection of the RPV studs, nuts, and washers. The procedure describes the inspecting and reporting of studs, nuts, and washers for any damage that is found. [Reference 20, Section 6.2].

Maintenance Procedure RV-22 is also credited for the discovery of general corrosion on the RPV head and vessel O-ring flange sealing area. This procedure provides for inspection and acceptance criteria for minor pitting, nicks, and scratches near or on the O-ring sealing area. [Reference 21, Section 6.3] Any evidence of general corrosion would be found during the performance of this procedure.

The Boric Acid Inspection Program has evolved to account for operational experience. Reactor Coolant System leakage has been discovered that has affected the focus of subsequent inspections. For example: (1) A Unit 2 pressurizer heater sleeve was discovered to have a leak, and as a result, CCNPP instituted a more comprehensive inspection of the pressurizer heater sleeves in Unit 1; and (2) A seal vent line in containment developed a leak which dripped onto and caused surface corrosion of a RCS elbow resulting in increased attention with the program to such leaks.

Both CCNPP Units have had occurrences of boric acid leakage through the ICI flange connections. In March, 1993 (Unit 2) and February 1994 (Unit 1), evidence of boric acid leakage and corrosion were discovered on the ICI flanges and flange nuts. The cause was a change of gasket material which changed the required gasket crush force. Boric acid deposits were discovered on the ICI flanges and RPV head insulation, and the potential for wastage of the head material was noted. [Reference 22, page 2]

Additionally, the program has evolved with regard to the qualification level of personnel for evaluating boric acid leaks. The program dictates a minimum qualification level of non-destructive examination Level II Inspector for the evaluation of boric acid leaks. Any person conducting a walkdown or inspection may discover boric acid leakage. Such leakage would then be documented in an IR by the individual discovering the leak, and routed to the ISI group for closer inspection and evaluation by a Level II Inspector. This approach provides for wide boric acid leakage inspection coverage, but ensures boric acid leakage and its effects are evaluated by qualified individuals.

The corrective actions taken as a result of IRs under this program and previously discussed programs will ensure that the RPV components remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 1 (general corrosion) - Demonstration of Aging Management

Based on the material presented above, the following conclusions can be reached with respect to the corrosion of the RPV components:

- The RPV components provide the RCS pressure-retaining boundary and provide structural support to the RPV, while allowing limited motion for thermal expansion.
- General corrosion is plausible for RPV components listed here and could lead to loss of the pressure-retaining boundary or structural support function.
- The CCNPP Boric Acid Corrosion Inspection Program provides for examination of boric acid on carbon steel surfaces, and provides appropriate corrective action to prevent corrosion if boric acid leakage is found.
- The CCNPP ISI Program provides for the inspection of RPV support components per the requirements of ASME Section XI. Though general corrosion is not expected, the status of the

components can be evaluated on a regular basis to ensure that these components are not subjected to an environment conducive to general corrosion.

- The CCNPP Procedure RV-62 provides for supplemental visual examination of the RPV studs, nuts, and washers.
- The CCNPP Procedure RV-22 provides for supplemental visual examination of the RPV head O-ring grooves and flange areas.
- Examinations will be performed, and appropriate corrective actions will be taken, if corrosion is discovered.

Therefore, there is reasonable assurance that the effects of corrosion on RPV components will be managed in order to maintain the components pressure boundary integrity under all design conditions required by the CLB during the period of extended operation.

Group 2 (wear) - Materials and Environment

Table 4.2-2 shows that wear is plausible for the RPV, CEDM, and RVLMS components. This group of components and their material composition are listed below: [Reference 2, Attachments 4, 5, and 6]

- RPV vessel flanges (threaded stud holes) (SA-508-64 Class II Forging);
- RPV head closure studs, nuts and washers (A-540 Grade 23 Class III and A-540 Grade 24 Class III);
- ICI tube nozzle flanges (SA-182, Type 316);
- ICI tube nozzle flange bolts and nuts (SB-637 or SA-453 Grade 660);
- RPV core stabilizing lugs (SB-166 Alloys 600 and X-750) and snubber spacer blocks (A-240-63). The snubber spacer blocks are hard faced with Stellite to minimize wear. [Reference 1, Figure 3.3.-12];
- RVLMS blind flange adapter hub vent plug and flange nut (SA-479 Type 316 stainless steel);
- CEDM ball seal housing (SA-479 Type 316 stainless steel);
- CEDM and RVLMS upper housing assembly steel balls (Type 440 stainless steel);
- Grayloc clamp set (SA-182 Type 304 stainless steel);
- Grayloc clamp studs and nuts (SA-453 Grade 660 Grade A or B with Chrome plating on stud threads); and
- Seal plug drive nut (SA-479 Type 347 stainless steel).

The internal environment of the RPVs and CEDMs is that of the RCS, which contains water at an operating pressure of approximately 2250 psia. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1] Certain RPV components are removed/disassembled and reinstalled for refueling outages. Many of these RPV components are tightly joined together to form the RCS pressure boundary.

Group 2 (wear) - Aging Mechanism Effects

Components such as the RPV closure head studs, nuts, and washers; the ICI tube nozzle flanges, studs, and nuts, and some of the internal components (core stabilizing lugs and snubber spacer blocks), are susceptible to mechanical wear due to the relative motion between them, and therefore, wear is a plausible ARDM. Mechanical wear is the deterioration of a surface due to material removal caused by the motion between contacting surfaces. [Reference 2, Attachments 5, 6, and 7] The Stellite facing on the snubber spacer block is a design feature that minimizes the effects of wear of these components. [Reference 1, Figure 3.3-12]

Long-term exposure to wear could lead to material loss and, if unmitigated, could eventually result in loss of the pressure-retaining capability and reduced ability to limit flow-induced vibrations in the core support barrel (core stabilizing lugs and snubber spacer block) under CLB design loading conditions. Therefore, mechanical wear was determined to be a plausible ARDM for which aging effects must be managed for areas of the RPVs and CEDMs/Electrical System components mentioned here.

Group 2 (wear) - Methods to Manage Aging

Mitigation: Mechanical wear on those components that are manipulated during refueling operations can occur; but, they usually are not subject to mechanical wear during normal operation. Minimizing the amount of component manipulation can mitigate wear. Those components that are normally not manipulated mitigate wear by proper design and material selection.

Discovery: With proper design, mechanical wear occurs slowly and over long periods of time, and is revealed as material loss of the components themselves. This wear can be discovered and monitored by visual inspection of the affected areas. Visual inspections of components can find any potential mechanical wear on the components. Wear of CEDM and RVLMS vent balls will lead to minor leakage and an indication of boric acid leakage at the normally inaccessible CEDM and RVLMS vent balls. This will lead to a more thorough examination of the components and, if required, will result in their being replaced. [Reference 2, CEDMs, Attachment 2].

Indications of wear identified during visual examinations of RPVs and CEDMs/Electrical System components during refueling outages must be recorded and evaluated for potential damage. Evidence of mechanical wear that will compromise the components intended functions before the next inspection must be repaired.

Group 2 (wear) - Aging Management Program(s)

Mitigation: There are no programs credited for the mitigation of wear beyond that provided by the original selection of materials and design of joints and interfaces, and by standard industry methods for tensioning and detensioning components.

Discovery: Inservice inspection is the existing program designed to detect and manage the effects of wear for the RPVs and CEDMs/Electrical System components. Visual examination performed by the ISI Program will readily detect wear in the RPV studs, nuts, and washers; the RPV flanges (threaded stud holes); the core stabilizing lugs; and snubber spacer blocks. The mechanical maintenance procedures perform supplementary visual inspections for the ICI flanges and for the RPV studs, nuts, and washers. [Reference 2, RPV, Attachment 8] The Long Term ISI Plan implements the requirements of Section XI of the ASME Code, 1983 Edition through Summer 1983 Addenda. [Reference 15, Section 1.2.1] For a detailed description of the ISI process, refer to the discussion under General Corrosion-Aging Management Programs.

In addition to the ISI Program, credit is taken for CCNPP Procedure RV-62 for the discovery of wear. [Reference 2, RPV Attachment 8] This procedure specifies the procedural steps, materials, and acceptance criteria to be used in the cleaning and inspection of the RPV studs, nuts, and washers. The procedure describes what the inspection process should be looking for, and how to report any wear or damage that is found. RV-62 also lists the acceptance criteria for contact between load bearing surfaces as a minimum of 70 percent. [Reference 20, Section 6.2] Specific instructions are provided in the procedure for the operation of equipment used in the cleaning of RPV studs and nuts.

Calvert Cliffs procedure RV-85, "ICI Flange Cleaning and Inspection," is credited for the discovery of wear. [Reference 2, RPV, Attachment 8] The procedure refers to the inspection of the ICI flanges for scratches, nicks, steam cuts, gouges, or rolled metal, and the documentation of any findings of wear. [Reference 23, Section 6.2 and Attachment 1]

Calvert Cliffs procedure RVLMS-2, "Installation of the Flexible HJTC in the Reactor," is credited for the discovery of wear. RVLMS-2 will be modified to include statements that visual inspection of Grayloc clamps, the RVLMS flanges, the associated studs and nuts, and seal plug, and drive nut are to be performed each time the RVLMS housings are reassembled. Components of the RVLMS will be replaced as necessary, based on the results of the inspection. [Reference 2, CEDM, Attachment 8 and 10]

The Boric Acid Corrosion Inspection Program is also credited here for finding wear on the CEDM and RVLMS vent balls. During the boric acid inspection process, evidence of boric acid at these locations would indicate that the CEDM and RVLMS vent balls were experiencing wear and would need to be replaced. [Reference 2, CEDM, Attachment 8] For a description of the CCNPP Boric Acid Corrosion Inspection Program, refer to the discussion under Group 1 (general corrosion), Aging Management Programs.

The existing CCNPP Maintenance Procedures listed here have been in use to clean and inspect RPV components, and thus supplement the ISI Program by providing another means to find any degradation of these components before their intended function is compromised.

Inspections of the RPV studs, nuts, washers, and stud holes during every refueling outage ensures the closure components meet the design requirements. Stud removal from the RPV flanges has resulted in galling and thread damage on at least one occasion. Baltimore Gas and Electric Company analyzed the damaged threads and developed a repair modification package (FCR 82-0070) to install sleeves to restore the threaded connection integrity. The RPV design bases were reviewed and modified as part of this repair.

Group 2 (wear) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the wear of the RPVs and CEDMs/Electrical System components:

- The RPVs and CEDMs/Electrical System components provide a RCS pressure-retaining boundary and limit the flow induced vibrations in the core support barrel, so their integrity must be maintained under CLB design conditions.
- Mechanical wear is plausible for the components listed above, which could lead to material loss and reduced capability of the components to perform their passive intended function of maintaining the RCS pressure boundary and limiting vibrations.
- The CCNPP ISI Program provides for the inspection of the components listed above per the requirements of ASME Section XI. Though mechanical wear cannot be completely prevented, the status of the components can be evaluated on a regular basis and corrective actions can be taken as conditions indicate component wear.
- The CCNPP Boric Acid Corrosion Inspection Program provides for inspection around the CEDM and RVLMS vent areas. Inspection of these areas could indicate the presence of RCS leakage (dried boric acid) and the necessary replacement of vent balls due to wear.
- The CCNPP Procedure RV-62 involves the cleaning and inspection of the RPV studs, nuts, and washers, and thus performs supplementary visual inspection for the ISI Program.
- The CCNPP Procedure RV-85 involves the cleaning and inspection of the ICI tube nozzle flanges, and thus performs supplementary visual inspection for the ISI Program.
- The CCNPP procedure for installation of the HJTC, RVLMS-2, will be modified to include explicit visual inspection of the Grayloc clamps, RVLMS flanges, and the associated studs, nuts, and seal plug and drive nut. This modification will supplement the ISI Program for the surveillance of wear.

Therefore, there is reasonable assurance that the effects of wear will be managed in order to maintain the RPVs and CEDMs/Electrical System components' pressure boundary integrity and limiting flow induced vibrations in the core support barrel under all design conditions required by the CLB during the period of extended operation.

Group 3 (low-cycle fatigue) - Materials and Environment

Table 4.2-2 shows that fatigue is plausible for all RPV, CEDM, and RVLMS components under review in this section, except for RPV support components and snubber spacer blocks. The RPV was evaluated and low-cycle fatigue was determined to be plausible because of cyclic stress loads that result from normal operation and maintenance. The locations of interest for low-cycle fatigue are the RPV main coolant outlet nozzles and closure head flange studs. All other RPV components/subcomponents are considered to have low susceptibility to low-cycle fatigue. [Reference 2, RPV, Attachments 4, 5, and 6]

The RPVs and CEDMs were designed in accordance with the ASME Section III, Nuclear Vessels (Class A) Winter 1967 Addenda to the ASME B&PV Code. [Reference 1, Section 4.1.1.1 and Tables 4-8 and 4-9] The RPV outlet coolant nozzles are fabricated from SA-508-64, Class II steel and are attached to the upper shell plates of the RPV. The RPV closure studs are made of A-540 Grade 23 and A-540 Grade 24 Class III. [Reference 2, Attachment 4]

The internal environment of the RPVs and CEDMs is that of the RCS, which contains water at an operating pressure of approximately 2250 psia. Normal RCS operating temperatures are approximately 548°F in the cold leg and 599.4°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power and corrosion control. The RPVs and CEDMs/Electrical System is subjected to cyclic heat-up and cool-down during normal plant operation. The vessel closure head flange studs are placed under cyclic mechanical loading during vessel head attachment/removal and RCS heat-up and pressurization.

Group 3 (low-cycle fatigue) - Aging Mechanism Effects

Low-cycle fatigue is the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points, and which may culminate in cracks or complete fracture after a sufficient number of fluctuations. The low-cycle fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure. A component subjected to sufficient cycling with significant strain rates accumulates fatigue damage, which potentially can lead to crack initiation and crack growth. [Reference 24, page 4-7] The cracks may then propagate under continuing cyclic stresses.

The RPVs and CEDMs are subject to a wide variety of varying mechanical and thermal loads. Therefore, low-cycle fatigue is a plausible ARDM for all components in the scope of this section, except the RPV supports and snubber spacer blocks. [Reference 2, Attachments 5, 6, and 7] The RPV supports and snubber spacer blocks are not pressure boundary components, and are therefore not subject to the range of thermal and pressure stresses experienced by other RPV and CEDM components. Plant transients apply cyclical thermal loading and pressurization that contributes to low-cycle fatigue accumulation on the RPVs and CEDMs. The limiting locations for low-cycle fatigue are the RPV outlet coolant nozzles and RPV closure studs. The transient involving the greatest low-cycle fatigue accumulation for the RPV outlet coolant nozzles is the RCS cool-down from Mode 1 (i.e., full power) operation. For the RPV closure studs, the critical transient is the RCS heat-up. [Reference 25, Table 5-1]

Section III of the ASME B&PV Code (Winter 1967 Addenda) requires the design analysis for Class 1 vessels to address fatigue, and establishes limits such that initiation of fatigue cracks is precluded. Section III defines the threshold in terms of a cumulative usage factor (CUF). The low-cycle fatigue "damage" from a particular transient depends on the magnitude of the stresses applied. The summation of fatigue usage over all transients of all types is the CUF. Crack initiation is conservatively assumed to have occurred at a CUF equal to 1. [Reference 26]

The CUF can be determined from the actual transient history for the component and limits established on the number of transients. [Reference 27]

Group 3 (low-cycle fatigue) - Methods to Manage Aging

Mitigation: The effects of low-cycle fatigue can be mitigated by operational practices that reduce the number and severity of thermal transients on the RPV, and by proper design and material selection. For thick-walled components like the RPVs, the greatest membrane stresses due to thermal gradients and pressure occur during plant heat-up and cool-down. Significant stress cycles also occur from detensioning and retensioning RPV head studs for refueling. Therefore, the effects of low-cycle fatigue can be mitigated by operational practices that reduce the number and severity of pressure and thermal transients, by fuel management practices that minimize the number of refuelings, and by proper design and material selection.

Discovery: Fatigue cracks can be discovered by inspecting components, and the scope and frequency of inspections can be established based on the likelihood that fatigue cracks have initiated. As discussed above, low-cycle fatigue is accounted for in the original design in accordance with ASME Code Section III. Monitoring the number of design-basis transients and/or the accumulated fatigue usage can be used to predict the end of fatigue life.

The ASME Code Section III also provides accepted practices for analyzing Class I components for thermal fatigue combined with all other loads that must be considered under the CLB. An inspection program designed to identify crack initiation can be effective in discovering the effects of this aging mechanism prior to loss of the RCS pressure boundary function. The RPV closure studs, which are susceptible to mechanical (low cycle) fatigue, can be inspected during refueling outages when the RPV closure head is removed, and the RPV outlet coolant nozzles can be inspected during plant refueling.

Group 3 (low-cycle fatigue) - Aging Management Program(s)

Mitigation: As part of general operating practice, plant operators minimize the duration and severity of transitory operational cycles. Further modification of plant operating practices to reduce the magnitude and/or frequency of thermal transients would place additional unnecessary restrictions on plant operations. This is because the detection and monitoring activities discussed below are deemed adequate for effectively managing low-cycle fatigue in the RPV. No credit has been given to the 24-month fuel cycle since plant transients other than refueling could cause plant heat-ups and cool-downs.

Discovery: The CCNPP Fatigue Monitoring Program (FMP) records and tracks the number of critical thermal and pressure test transients. Cycle counting is performed as part of this program. The data for thermal transients is collected, recorded, and analyzed using FatiguePro software, which is a safety related software package. FatiguePro is used to analyze data that represents real transients. The FMP uses the results of FatiguePro to predict the number of transients for 40 and 60 years of plant operation. This information is used to verify that the RPV bounding locations will not experience more than 500 heat-up and cool-down cycles. [References 25, Tables 4-1 and 4-7; Reference 28] The Improved Technical Specifications for CCNPP, which will be implemented in 1997, will contain a requirement for tracking cyclic and transient occurrences to ensure that components are maintained within the design limits.

The current FMP monitors and tracks low-cycle fatigue usage for the selected components of the Nuclear Steam Supply System and the steam generators. Eleven locations in these systems have been selected for monitoring for low-cycle fatigue usage; they represent the most bounding locations for critical thermal and pressure transients, and operating cycles. [Reference 29] The RPV bounding locations for low-cycle fatigue are the RPV closure studs and RPV outlet coolant nozzles. The transient that has the greatest effect on fatigue life of the RPV coolant outlet nozzles are plant cool-down from Mode 1. For the closure head flange studs, the transient involving the greatest fatigue accumulation is plant heat-up. [Reference 25, Sections 4.1 and 4.8]

The design fatigue analysis (which was incorporated into the FMP) of the CCNPP RPVs determined the bounding locations and corresponding transients. Under the FMP, all other transients that contribute to low-cycle fatigue usage, including the RPV closure head flange stud tensioning, are accounted for as the initial fatigue usage. FatiguePro adds to subsequent fatigue usage resulting from RCS heat-up and cool-down transients to this "initial" fatigue usage to obtain the current CUF. [Reference 25, Sections 4.1 and 4.8; Reference 30]

The FMP tracks low-cycle fatigue usage using both cycle counting and stressed-based analysis. In accordance with ASME Code Section III, the fatigue life of a component is based on a calculated CUF of less than or equal to one. Cycle counting is used for the RPV outlet coolant nozzles and closure head flange studs, based on the original design transients in the ASME III, Class A design code analysis (Winter 1967 Addenda to the ASME B&PV Code). [Reference 1, Table 4-9; References 27, 28, 30]

Plant parameter data is collected on a periodic basis and reviewed to ensure that the data represents actual transients. Valid data is entered into FatiguePro, which counts the critical transient cycles and calculates the CUFs. Based on the ASME Code Section III, a CUF less than or equal to one, and/or the number of cycles remaining below the design allowable number, are acceptable conditions for any given component since no crack initiation would be predicted. The number of cycles and CUF are calculated on a semi-annual basis, which provides a readily predictable approach to the alert value. [Reference 27, Section 1.1] In order to stay within the design basis, corrective action is initiated well in advance of the CUF approaching one or the number of cycles approaching the design allowable, so that appropriate corrective actions can be taken in a timely and coordinated manner. [Reference 27]

The FMP will perform an engineering evaluation to determine if the low-cycle fatigue usage for the CEDM/RVLMS components are bounded by the existing bounding components. If they were not bounded, they will be added to the FMP. Tracking the usage for the limiting components ensures that all remaining components will also remain below their fatigue limits. [Reference 2, Attachment 2]

Modifications have been made to the FMP recognizing lessons learned. For example, analysis techniques, such as stress-based analysis, have been implemented for locations that have unique thermal transients or involve unique geometry. Other modifications have been made to reflect changes, or proposed changes, to plant operating practices to reflect plant operating conditions more accurately. The plant design change process requires the FMP to consider any proposed changes that affect the fatigue design basis or transient definitions. [References 28 and 32]

In conjunction with the FMP, the CCNPP ISI Program requirements, such as volumetric, visual, and/or surface examinations of Class I nuclear components, may discover unexpected crack initiation due to low-cycle fatigue. The requirements for specific components are outlined in ASME Section XI (Table IWB-2500) and flaw acceptance standards of IWB-3500, as implemented by the CCNPP ISI Program. [Reference 2, RPV, Attachment 6, Code O] Refer to the ISI Program discussion under Group 1 (general corrosion), Aging Management Programs.

Two CCNPP modifications have affected the RPV design basis loading. These involved the installation of permanent cavity seals and altering the stud tensioning sequence. The RPV design basis was reviewed for both of these modifications, and all fatigue loading changes were incorporated into the RPV analytical reports. The stud tensioning sequence modification did result in higher fatigue usage, but the analyzed end of life CUF is still below one. [Reference 32] As previously discussed, the FMP was modified to reflect these changes in plant operating conditions.

The CCNPP FMP has been inspected by the NRC, which noted that this monitoring system can be used to identify components where low-cycle fatigue usage may challenge the remaining and extended life of the components, and can provide a basis for corrective action where necessary. The program is controlled in accordance with the administrative procedures of the Life Cycle Management Program. [Reference 33] Since the FMP has been initiated, no locations have reached their design allowable number of cycles or a CUF of greater than or equal to one. The CUFs through 1996 for the RPV outlet coolant nozzles are 0.04537 (Unit 1) and 0.03349 (Unit 2). The CUF for the RPV closure studs is 0.28076 (Unit 1) and 0.25714 (Unit 2). [Reference 28]

To fully address low-cycle fatigue for license renewal, CCNPP has initiated an additional study, in conjunction with the Electric Power Research Institute, to evaluate the effects of low-cycle fatigue on various fatigue critical plant locations. The study will apply industry developed methodologies to identify fatigue sensitive component locations, which may require further evaluation or inspection for license renewal and evaluate environmental effects, as necessary. The program objective includes the development and justification of aging management practices for low-cycle fatigue at various component locations for the renewal period. [Reference 34]

Generic Safety Issue 166

Generic Safety Issue 166, Adequacy of Fatigue Life of Metal Components, presents concerns identified by the NRC which must be evaluated as part of the license renewal process. The NRC staff concerns about fatigue for license renewal fall into five categories: The first is adequacy of the fatigue design basis when environmental effects are considered. This concern does not apply to the RPV because of stringent RCS water chemistry controls, exceptionally low oxygen concentrations (less than five parts per billion), and because the RPV carbon steel interior surfaces are clad with stainless steel. The second category concerns the adequacy of both the number and severity of design-basis transients. Since these have already been analyzed for the CCNPP RPVs, this concern does not apply. A third category, adequacy of ISI requirements and procedures to detect fatigue indications, does not apply because CCNPP does not rely on ISI as the sole means for detection of fatigue. Category four, adequacy of the fatigue design basis for Class I piping components designed in accordance with ANSI B31.1, does not apply because the RPV and closure studs are designed in accordance with ASME Section III, Class I. The fifth and last category, adequacy of actions to be taken when the fatigue design basis is potentially compromised, as discussed above, are adequately addressed by the CCNPP FMP.

Group 3 (low-cycle fatigue) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the RPVs and CEDMs/Electrical System components subject to low-cycle fatigue:

- The RPV components have intended functions and their integrity must be maintained under CLB design conditions.
- Low-cycle fatigue is plausible for the entire RPV, except for the vessel support components and snubber spacer blocks.
- If left unmanaged, low-cycle fatigue could result in crack initiation and growth, which could impair the ability of the RPV to perform its intended function.
- The closure studs and outlet coolant nozzles are the bounding fatigue sensitive components for the RPV and are expected to bound the CEDM/RVLMS components.
- The CCNPP FMP tracks all applicable plant transients and monitors accumulated cycles and low-cycle fatigue usage for the bounding RPV components.
- The FMP is adequately controlled so that effective and timely corrective actions can be taken prior to a loss of RCS pressure boundary integrity resulting from fatigue damage.
- The FMP will be modified to include an engineering evaluation of the low-cycle fatigue usage for the CEDM/RVLMS components to ensure that their fatigue usage is bounded.
- Tracking the accumulated cycles and low-cycle fatigue usage for the bounding RPV components will ensure that all other RPV components will not exceed their fatigue design basis.
- ASME Section XI requirements provide for inspections that would discover cracks from any cause and require augmented inspections before fatigue crack initiation is expected.

Therefore, there is reasonable assurance that the effects of low-cycle fatigue in RPV components will be managed in order to maintain the components intended function under all design loading requirements of the CLB during the period of extended operation.

Group 4 (neutron embrittlement) - Materials and Environment

Table 4.2-2 shows that neutron embrittlement is plausible for only specific RPV components. This group includes the vessel plates and welds of the RPV lower shell, intermediate shell, and the lower portion of the nozzle shell courses. The RPV lower shell, intermediate shell, and the lower portion of the nozzle shell courses are fabricated from SA-533, Grade B, Class 1 low-alloy steel with an internal cladding of stainless steel. The associated welds are automatic submerged arc or manual metal arc with stainless steel cladding. [Reference 2, Attachments 4, 5, and 6]

The internal environment of the RPVs and CEDMs is that of the RCS, which contains chemically-treated, borated water at an operating pressure of approximately 2250 psia. Normal RCS operating temperatures are approximately 548°F in the cold leg and 599.4°F in the hot leg. The RCS flow rate during normal operation is approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1] The region of the

RPV, where the components of this group are located, is an environment where neutron fluence is at its maximum levels with respect to components covered by this section.

The threshold for onset of neutron effects for RPV materials is conservatively defined to be a fast neutron fluence that exceeds 1E17 n/cm^2. [Reference 35, Appendix H] Portions of the RPV are expected to exceed this fluence. Certain welds in CCNPP Unit 1 are more sensitive to neutron exposure than was originally expected because of the amount of impurities (copper) in the Unit 1 RPV axial weld. [Reference 36]

Group 4 (neutron embrittlement) - Aging Mechanism Effects

Low alloy ferritic steels (like the RPV manganese-molybdenum-steel plates) that are exposed to a neutron fluence greater than 1E17 n/cm^2 are known to undergo microstructure changes that elevate the temperature at which the material begins to lose ductility (embrittlement) and may reduce its fracture toughness at normal operating temperatures (loss of upper shelf energy, LUSE). These effects depend on the level of certain alloying materials (nickel) and impurities (copper), and on the accumulated neutron exposure. [Reference 24, Section 4.1; Reference 37, Section 4.2.2] Understanding of the variables that cause these effects and their interdependencies continues to improve and is the subject of ongoing research by industry and NRC.

Therefore, neutron irradiation could reduce the fracture toughness of certain RPV materials, which in turn could reduce the ability of those materials to withstand temperature and pressure transients, including Pressurized Thermal Shock (PTS) transients. [Reference 24, page 5-3] Pressurized Thermal Shock transients are characterized as a severe rapid cool-down of the RPV, coincident with high or increasing pressure. The combined thermal and pressure stresses during temperature transients affecting low toughness materials increase the potential for extending flaws that may be present [Reference 37, page A-3-21] Therefore, neutron embrittlement (with accompanying LUSE) is considered a plausible ARDM for these components.

Group 4 (neutron embrittlement) - Methods to Manage Aging

Mitigation: The effects of neutron embrittlement and LUSE cannot be prevented, but can be mitigated by minimizing the neutron fluence to sensitive components, by using materials that are insensitive to these effects, and by reducing allowed system pressure during temperature transients and at reduced temperatures. Excessive neutron embrittlement and LUSE can be partially remedied by thermal annealing of the affected components.

Discovery: Practical methods to directly monitor neutron embrittlement of RPV components do not currently exist. However, this embrittlement can be monitored by periodic testing of coupons of representative RPV materials installed within the CCNPP RPVs, at another plant, or in test reactors. [Reference 35, Appendix H] Since the neutron exposure of the coupons is higher than that of the RPV, the embrittlement through the current license period and the period of extended operation can be predicted. These predictions can be adjusted to account for changes in fuel management, for the results of subsequent tests, and for subsequent research results.

Group 4 (neutron embrittlement) - Aging Management Program(s)

Mitigation: The current regulations require that neutron embrittlement and LUSE be managed. They establish specific embrittlement and LUSE limits; establish limits on pressure, temperature, and temperature transients; and require controls to minimize the potential for excessive stresses from pressure and temperature transients. [Reference 35, Section 61 and Appendix G] These mitigation elements are established at CCNPP by the LTOP controls, Pressure-Temperature limits, and neutron fluence limits included in Technical Specifications. No credit is taken for mitigation beyond those established in response to the regulatory requirements.

Discovery: The regulations require periodic testing of representative coupons of RPV materials to monitor neutron embrittlement and LUSE. [Reference 35, Section 61 and Appendix H] The CRVSP implements the requirements of 10 CFR Part 50, Appendix H, and provides the necessary data to monitor the embrittlement status of the reactor vessels. [Reference 1, Section 4.1.4.5] Calvert Cliffs has five surveillance capsules for each unit to provide sufficient RPV material property changes and fluence information as suggested in American Society for Testing and Materials (ASTM) E185-82 to meet the requirements of 10 CFR Part 50, Appendix H, through the current license period. Each CCNPP Unit also has one standby surveillance capsule to meet future needs (e.g., life extension, radical fuel management changes, etc.), as required. [Reference 38]

Because certain Unit 1 welds may be more susceptible to neutron embrittlement than originally expected, and because the RPV materials included in the original CCNPP surveillance program are less susceptible than the critical weld, BGE further extended this program into a CRVSP beginning in 1991. This CRVSP includes elements to identify and obtain test results and materials representative of the CCNPP RPVs from all available sources. The results of this ongoing program are chronicled extensively in the docketed submittals and responses as listed in References 39, 40, and 41. The results of this ongoing program include:

- Review of fabrication records for RPVs fabricated by CE to identify potential sources of information and archive material [Reference 39];
- Detailed review of CE fabrication records and industry databases to ensure all available data are properly considered [Reference 39];
- Incorporation of surveillance results from other plants that have surveillance coupons made using heats of weld wire identical to those in CCNPP beltlines [Reference 10, McGuire-1 Section];
- Acquisition of archival material and portions of the decommissioned reactor vessel from the Shoreham nuclear power plant made using heats of weld wire identical to those in CCNPP beltlines [Reference 10, Archive Section];
- Extensive chemical analysis of Shoreham and archival materials to assess chemical variability of RPV welds [Reference 39]; and
- Fabrication and installation of a supplemental Unit 1 surveillance capsule in 1988 containing the RPV material expected to be most affected by neutron irradiation. [Reference 10, Supplemental Surveillance Section]

These results to date demonstrate that CCNPP RPVs will remain well within established regulatory limits through the period of extended operation. NRC accepted these results as documented in the NRC correspondence listed in References 42, 43, 44, and 45.

This section of the BGE LRA is submitted to satisfy the requirements of 10 CFR 50.61(b)(1), which requires an updated assessment of the projected value of PTS "upon requests for a change in the expiration date for operation of the facility.". The NRC accepted BGE's results that CCNPP Units 1 and 2 beltline material are projected to be below PTS screening criteria 20 years after the original 40-year operating license. However, NRC noted that future chemistry and surveillance data may change their assessment. [Reference 42] Baltimore Gas and Electric Company recognized this possibility and purchased the rights to the surveillance capsule located in another pressurized water reactor. This capsule in another plant, as noted above, has provided for obtaining additional data for the Unit 1 material predicted by current regulations to be most susceptible to neutron irradiation effects. This data is expected to bound the neutron fluence of the subject RPV components through the period of extended operation, and to be available well before the period of extended operation. The CCNPP Unit 1 supplemental surveillance capsule also contains material identical to that material purchased above. Baltimore Gas and Electric Company's CRVSP provides for testing it in the next several years to provide further assurance that surveillance results from other plants reliably predict the behavior of CCNPP RPVs. [Reference 10, Supplemental Surveillance Section]

In addition, BGE is participating in CE Owners Group programs targeted toward improving the accuracy of current methods and industry standards for determining the resistance of RPV materials to initiation and propagation of cracks (fracture toughness). [Reference 46]

The regulations already require embrittlement and LUSE projections be updated to account for any significant changes in the projected values of RT_{PTS} or change in the expiration date for operation of the facility. [Reference 35, Section 61] Baltimore Gas and Electric Company will continue to make periodic adjustments of neutron embrittlement and LUSE predictions, as needed, to account for any new information on the RPV beltline materials.

Therefore, there is reasonable assurance that the affects of neutron irradiation on the CCNPP RPVs will be known and future results will be addressed. Additional alternatives (e.g., annealing, further flux reduction, shielding) also remain that can be pursued if necessary.

Group 4 (neutron embrittlement) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the neutron embrittlement of RPV cylindrical shell plates and their associated welds:

- The vessel plates and welds of the RPV lower shell, intermediate shell, and the lower portion of the nozzle shell courses contribute to the RPV intended function, and their integrity must be maintained under CLB design conditions.
- These components are subject to significant neutron irradiation (fluence) due to their close proximity to the reactor core, and neutron embrittlement and LUSE are therefore plausible for the components. If not managed, these affects could result in sufficient loss of fracture toughness to

impair the ability of the RPV to perform its intended function under CLB design loading conditions.

- The CLB provides for monitoring the RPV materials for the effects of neutron irradiation, it provides specific limits on embrittlement and LUSE, it requires action before these limits are exceeded, and it provides specific constraints on operations to ensure allowable stresses are not exceeded.
- Baltimore Gas and Electric Company has demonstrated that the CCNPP RPVs will continue to meet CLB limits for embrittlement and LUSE for 60 years of operation, and has augmented its surveillance program to obtain embrittlement information that will bound the period of extended operation. NRC has concurred with this demonstration, noting that future test results may change this assessment.
- The CLB specifically requires that future test results for representative RPV materials be addressed and appropriate action taken such that RPV intended functions are assured.

Therefore, there is a reasonable assurance that the effects of neutron irradiation (embrittlement, LUSE) will be managed in order to maintain the RPV intended functions under all design conditions required by the CLB during the period of extended operation.

Group 5 (stress corrosion cracking) - Materials and Environment

Table 4.2-2 shows that SCC is plausible only for RPV support anchor bolts and for specific RPV components made of Alloys 600 and X-750. The RPV components susceptible to SCC and their material composition are the following: [Reference 2, Attachments 4, 5, and 6]

- RPV leakage monitoring tube (SB-167, SB-166);
- RPV ICI tube nozzle, Vent pipe, and CEDM nozzles (SB-167);
- RPV flow skirt (SB-168);
- RPV core stop lugs (SB-168);
- RPV core stabilizing lugs (SB-166 Alloys 600 and X-750);
- RPV surveillance capsule holders (SB-167, SB-167-65); and
- RPV anchor bolts (A-354 Grade B6).

The internal environment of the RPVs and CEDMs is that of the RCS, which contains chemically-treated water at an operating pressure of about 2250 psia. Normal RCS operating temperatures are approximately 548°F in the cold leg and 599.4°F in the hot leg. The normal RCS flow rate is approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1] The RPV anchor bolts are embedded in the concrete primary shield wall with the upper portions exposed to the containment environment. The containment environment is discussed in Group 1 (general corrosion).

As a result of the experience in 1989 and 1994 with minor Pressurizer Heater Sleeve leakage, BGE has replaced or scheduled near-term replacement of high-susceptibility Alloy 600 pressure boundary components. [Reference 6, Section 2]

The components identified as SB-166, 167, and 168 are susceptible to PWSCC. The following discussion on Alloy is also applicable to those components made of X-750.

Group 5 (stress corrosion cracking) - Aging Mechanism Effects

Alloy 600 materials and the RPV anchor bolts are susceptible to SCC, which occurs by the combined and synergistic interaction of a chemically-conducive environment, susceptible material, and tensile stress. Over long periods of time, Alloy 600 fails by slow, environmentally-induced crack initiation and growth, which may lead to eventual macroscopic plastic deformation. Understanding of the variables that cause these effects and their interdependencies continues to improve and is the subject of ongoing research by industry worldwide and by NRC. For the RPV anchor bolts, SCC would exhibit itself as continued cracking and eventual failure that could impair the supports' ability to withstand design basis loads.

Experience to date for Alloy 600 PWSCC indicates that for nozzles, cracks initiate first in the vicinity of penetrations (due to the higher residual stresses from welding the nozzles to the vessel/head), and then grow axially. The resulting cracks are short, grow slowly, grow at comparable rates axially and radially (through wall), and result in very minimal leakage when through-wall penetration finally occurs. For the portion of the nozzle external to the pressure boundary, crack growth that exhibits significant propagation around the circumference in a narrow axial region before penetrating through-wall would cause concern for separation and rapid development of significant leakage. [Reference 47]

Although safety concerns are minimal for Alloy 600 pressure boundary components, economic impacts can be significant since the ASME Code and NRC Regulations require the plant be shutdown for repair of any pressure boundary leakage. In addition, since circumferential cracking could lead to one or more design basis events (Loss of Coolant Accident, CEA Ejection), one cannot completely discount the potential for circumferential cracks that exhibit substantially greater circumferential growth rates than radial growth rates, based on the information presently available.

Therefore, the RPV components described above are considered susceptible to PWSCC, are exposed to an environment known to be conducive to PWSCC, and are placed under high tensile stresses. [Reference 2, Attachments 6 and 7] The combined effect of these factors could result in reduction of the ability of the components to maintain the RCS pressure boundary, to detect RCS leakage past the inner O-ring (leakage monitoring tube), to direct primary coolant flow through the core (flow skirt), to prevent excessive core displacement under specified accident conditions (core stop lugs), to limit flow induced vibrations in the core barrel (core stabilizing lugs), to support surveillance capsules (surveillance capsule holders), and to support the RPV position (RPV anchor bolts) under CLB design loading conditions. Therefore, SCC is a plausible ARDM for this group of components. [Reference 2, Attachments 4, 5, 6, and 7]

Group 5 (stress corrosion cracking) - Methods to Manage Aging

Mitigation: The effects of SCC on Alloy 600 materials in the RCS cannot be eliminated, but can be monitored and actions taken to mitigate the effects. Sleeving, plating, weld overlays, thermal treatment, and replacement with material less susceptible to SCC can also be used to mitigate or remedy the effects of SCC. There are no methods to mitigate SCC on RPV anchor bolts. The effects of SCC could not be mitigated further for the RPVs and CEDMs/Electrical System beyond the strict chemistry control already used in the RCS. See the discussion of the RCS chemistry control program in Section 4.1 of the BGE LRA.

Discovery: Stress corrosion cracking of Alloy 600 components and RPV anchor bolts can be discovered and monitored by inspection programs. Inspection methods and frequencies can be defined based on susceptibility of the components, and inspection results from other facilities can be used to adjust the predicted susceptibility, inspection methods, and frequency of inspection.

Given the expected axial nature of Alloy 600 nozzle PWSCC cracks, the slow growth rates, the minimal leakage that occurs once through-wall penetration does occur, and the low safety concern, periodic inspections of low-susceptibility pressure boundary penetrations for evidence of leakage are sufficient. Dedicated inspection of high-susceptibility pressure boundary and non-pressure boundary components could be conducted and be timed based on expected initiation of cracks and expected propagation rates. This technique would have a high probability of discovering SCC effects prior to the loss of intended function.

Detection of PWSCC cracks shortly after they have initiated would permit timely repair, long before the intended function is jeopardized, and might minimize the cost and complexity of repair. Ranking models could be used to estimate PWSCC susceptibility and to schedule inspections based on the potential for crack initiation.

Group 5 (stress corrosion cracking) - Aging Management Program(s)

The CCNPP Alloy 600 Program Plan was developed in response to primary pressure boundary leakage at CCNPP and other plants caused by PWSCC. The CCNPP Alloy 600 Program Plan builds on CCNPP and industry experience and provides for systematic evaluation of Alloy 600 pressure boundary components in the RCS, including the RPV and Pressurizer. It addresses nuclear safety concerns and identifies actions to minimize the safety and economic impact of SCC of Alloy 600 components. The program defines mitigation and discovery alternatives, as discussed below, and provides the process for considering susceptibility, safety, and economics in selecting from these alternatives. It also includes measures for monitoring industry experience and making appropriate adjustments based on this experience.

The susceptibility to PWSCC was evaluated for each CCNPP Alloy 600 nozzle based on ranking models developed by both Westinghouse and CE. A susceptibility index calculated from the Westinghouse model is a function of microstructure, effective stress factor, and temperature factor. The susceptibility index is used to develop a Relative Susceptibility Index, which is the susceptibility index of the component under analysis, as compared to the susceptibility index of the reference/benchmark component. The reference components in this case are the CCNPP Unit 2 Pressurizer heater sleeves, which developed minor leakage in 1989. The Relative Susceptibility Index is then multiplied by the actual or effective full power hours to obtain a time-dependent Relative Cumulative Susceptibility Index.

The CE model was used for the RCS Alloy 600 nozzles with inputs that were generic to all welded-tube type Alloy 600 nozzles; temperature, time in effective full power hours, and applied stress, which is based on the geometry of penetration and material yield strength. The CE model was used to calculate crack initiation probabilities as a function of effective full power hours. [Reference 6, Section 7].

The calculated susceptibility and crack initiation probability results were used to rank the nozzles and to develop recommendations for inspection, mitigation, repair and/or replacement of the nozzle(s). [Reference 6, Section 8] The susceptibility and economic analyses are used to select from the following options available for nozzles: [Reference 6, Section 9]

- Repair/replace nozzles based on susceptibility assessment.
- Perform mitigating techniques based on susceptibility assessment.
- Continue visually inspecting each nozzle as required by the boric acid corrosion program.
- Be prepared to repair nozzles on an as-failed basis. This option requires BGE to have replacement nozzles, repair plans, and design packages ready prior to the discovery of leakage.
- Perform augmented inspection to find non-throughwall PWSCC and perform repair/replacement as necessary.

Nuclear safety, ALARA (as low as reasonably achievable), and economics, are considered when selecting mitigating steps or repair/replacement for nozzles susceptible to PWSCC. Nuclear safety considerations include whether a complete severance of the nozzle due to circumferential cracking could lead to an unisolable small break loss-of-coolant accident, whether stresses would exist that could lead to such circumferential cracking, and whether a nozzle would exhibit minor leakage before crack growth would cause rapidly increasing leakage. [Reference 6, Section 14].

The focus of this program to date has been on pressure boundary components. This is appropriate given their greater stresses and greater potential to initiate design basis events. This program plan will be modified to include all Alloy-600 components in the RCS and RPVs, in addition to those that form the pressure boundary. [Reference 2, Attachments 2 and 10].

Mitigation: No program has been credited with mitigating the effects of SCC on RPV anchor bolting.

The CCNPP Alloy 600 Program Plan provides additional mitigation alternatives that include the following techniques: [Reference 6, Section 11]

- Shot peening - This induces compressive residual stress, slowing PWSCC initiation.
- Sleeving - A sleeve of Alloy 690 (less susceptible to PWSCC) is rolled and/or welded in existing Alloy 600 sleeves.
- Weld overlay - A thin layer of welded metal with a composition equivalent to Alloy 690 is deposited over the high stress area of the Alloy 600.

- Nickel plating - This technique provides a barrier to the primary water.
- Thermal treatment - Conducted in-situ to reduce residual stress.
- RCS temperature reduction - Reduces the thermodynamic driving force for PWSCC.
- Zinc Injection - Zinc added to the primary water may slow initiation and growth of PWSCC cracks.
- Mechanical stress improvement - controlled plastic deformation of the nozzle(s) in a manner which creates compressive residual stresses at locations susceptible to SCC (the technique has been used extensively in Boiling Water Reactor plants on stainless steel pipe fittings, weldments, and nozzles).

If mitigation techniques are not sufficient, then corrective actions are provided for nozzle(s) repair or replacement. The Alloy 600 Program Plan includes the following options to repair or replace nozzles: [Reference 6, Section 12]

- Local weld repair of defects;
- Replacement with Alloy 690 sleeves;
- Removal from service/plugging of a nozzle; or
- Encapsulate the existing nozzle in an outer nozzle bolted to the vessel to convert the nozzle into a bolted gasketed joint.

Discovery: The CCNPP ISI Program is credited with discovering SCC on the RPV anchor bolts. These RPV anchor bolts will be visually examined as defined in IWF-2500 of the ASME Code Section XI, and acceptance criteria contained in IWF-3410 of the ISI Program previously described in the Aging Management Program(s) section under Group 1 (general corrosion). [Reference 2, Attachment 6, Code S] The Boric Acid Corrosion Inspection Program augments the ISI Program for the discovery of SCC on the RPV anchor bolts. Refer to the Aging Management Program(s) in Group 1 (general corrosion) for a description of the Boric Acid Corrosion Inspection Program.

All RCS Alloy 600 nozzles are visually inspected each refueling outage for indications of leakage by the Boric Acid Corrosion Inspection Program. [Reference 18] Leakage that develops between refueling outages will be detected before significant through-wall leakage develops as a result of the Technical Specification limits on leakage. The Alloy 600 Program Plan also includes provisions for augmented inspection based on susceptibility.

RCS nozzles are evaluated under the Alloy 600 Program Plan based on primary and secondary factors. The primary evaluation factors for PWSCC susceptibility include: [Reference 6, Section 8]

- Operating temperature;
- Material peak stress level;
- Material heat treatment, if known;
- Number of Effective Full Power Hours; and

- Previous industry failures of same material heat.

The secondary evaluation factors for PWSCC susceptibility include: [Reference 6, Section 8]

- Industry susceptibility rankings;
- Amount and type of machining/rework on a component during fabrication;
- Product form (i.e., bar, tubing, pipe);
- Whether a crevice environment exists;
- Potential for trapping contaminants due to isolation from flow circulation (stagnation);
- History of chemical excursions; and
- General susceptibility of nozzle type.

Susceptibility rankings based on predictive models cannot be used to predict the exact timing of crack initiation or progression through-wall. Primary water stress corrosion cracking initiation times for identical materials vary over a wide band, and predictive models take into account a limited number of parameters. Detailed study of material properties, fabrication, and service history is required to assess susceptibility of individual nozzles. However, the susceptibility models are used to allow susceptibility comparison. The CE model is used in the economic analysis to determine the optimal time for augmented inspections, but not as the basis for safety evaluations. [Reference 6, Section 7]

The cracking initiation probability from the CE Model and the Relative Cumulative Susceptibility Index results are used for analyzing nozzles to determine when to perform augmented inspections for crack initiation. Alternatives for augmented nozzle inspections include eddy current, dye penetrant, and ultrasonic examination. [Reference 6, Section 10]

Relevant operating experience applicable to PWSCC includes failure of purification system resin retention screens. These resulted in a Unit 1 resin intrusion in March 1989, and a Unit 2 resin intrusion in January 1983. Resin decomposition products may contribute to cracking of sensitized Alloy 600, and an evaluation of the 1989 event by CE and BGE concluded that the increase in susceptibility to PWSCC was insignificant. [Reference 7]

Alloy 600 PWSCC has occurred at CCNPP and at other domestic and foreign pressurized water reactors, and BGE has been a leader in industry efforts to understand and manage PWSCC. [Reference 6, Section 3] The Alloy 600 Program Plan is a relatively new program, having been initiated in 1992. Since this program achieved its present form in 1995, no pressure boundary leakage has occurred as a result of PWSCC.

The Alloy 600 Program Plan includes specific provisions for monitoring industry experience and adjusting the plan accordingly. MN-3-304, Control of the Alloy 600 Program Plan, establishes administrative controls for this program under the site procedures hierarchy. The Alloy 600 Program Plan will continue to examine pressure boundary components susceptible to PWSCC to ensure that these components maintain their intended function required by the CLB during the period of extended operation. The program will be modified to include all Alloy 600 components that require AMR, including the above RPV components.

Group 5 (stress corrosion cracking) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to SCC of the RPVs and CEDMs/Electrical System components:

- The RPV anchor bolts maintain the RPV position and are subject to SCC and the supports' integrity must be maintained under CLB design loading conditions.
- The components subject to PWSCC provide the RCS pressure-retaining boundary, monitor RCS leakage (leakage monitoring tube) into and from the space between the vessel head O-rings, reduce core inlet flow inequalities and prevent formation of large vortices (flow skirt), prevent excessive core displacement under specified accident conditions (core stop lugs), limit flow induced vibrations in the core barrel (core stabilizing lugs), and support surveillance capsules. Their integrity must be maintained under CLB design conditions.
- Although the susceptibility of pressure boundary components to PWSCC is low relative to most other plants, SCC is plausible for the components mentioned above, and could impair their ability to perform their intended functions.
- The CCNPP Alloy 600 Program Plan provides for actions to assess susceptibility and take action to mitigate, inspect, repair, or replace based on the results. It schedules augmented inspections when crack initiation is predicted to be more likely.
- The CCNPP Alloy 600 Program Plan includes provisions for monitoring and incorporating industry experience.
- The Alloy 600 Program Plan will be modified to include all applicable Alloy-600 components in the RCS, in addition to the RCS pressure boundary components.
- The CCNPP ISI Program, per the requirements of ASME Section XI, and Boric Acid Corrosion Inspection Program, provide for examination of RPV anchor bolts. Though SCC cannot be completely prevented, the status of the components can be evaluated on a regular basis and corrective actions can be taken as conditions indicate SCC.

Therefore, there is reasonable assurance that the effects of SCC and PWSCC will be managed in order to maintain the RPV intended functions under all conditions required by the CLB during the period of extended operation.

4.2.3 Conclusion

The programs discussed for the RPVs and CEDMs are listed on the following table. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the RPVs and CEDMs will be maintained, consistent with the CLB during periods of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to an AMR.

TABLE 4.2-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE RPVs AND CEDMs / ELECTRICAL SYSTEM

	Program	Credited As
Existing	CCNPP RV-22 RPV O-Ring Replacement	Discovery of general corrosion (Group 1) on the RPV head and vessel.
Existing	CCNPP MN-3-301, Boric Acid Corrosion Inspection Program	Discovery and mitigation of the effects of general corrosion (Group 1), discovery of mechanical wear (Group 2), and discovery of PWSCC on Alloy 600 nozzles (Group 5).
Existing	CCNPP RV-85, ICI Flange Cleaning and Inspection	Discovery of wear (Group 2) on the ICI tube nozzle flanges and associated components.
Existing	CCNPP RV-62 RPV, Stud, Nut, and Washer Cleaning	Discovery of wear (Group 2) and general corrosion (Group 1) on the RPV studs, nuts and washers.
Existing	CCNPP CRVSP	The CRVSP implements and augments the requirements of 10 CFR 50.61, Appendices G and H, to monitor the effects of neutron embrittlement (Group 4) of the RPV.
Existing	CCNPP ISI Program	Discovery, per ASME XI, and management of the effects of mechanical wear (Group 2), general corrosion (Group 1), and SCC (RPV anchor bolts in Group 6) on those RPV components susceptible to these ARDMs.
Modified	CCNPP RVLMS-2, Installation of the Flexible HJTC in the Reactor	Discovery of wear (Group 2) on the RVLMS flanges and associated components. RVLMS-2 will be modified to perform visual inspections of the Grayloc clamps, studs, nuts; and HJTC seal plug and drive nut for wear each time the RVLMS housing is reassembled.
Modified	CCNPP EN-1-300 FMP Procedure "Implementation of Fatigue Monitoring"	Discovery and management of the effects of low-cycle fatigue (Group 3). The FMP will be modified to perform an engineering evaluation for CEDM/RVLMS components to ensure that the components are bounded.
Modified	CCNPP Alloy 600 Program	Discovery and mitigation of the effects of PWSCC (Alloy 600 and Alloy X-750 materials in Group 5) on susceptible components. The Alloy 600 Program will be modified to include all Alloy-600 components, not just those which form the pressure boundary.

4.2.4 References

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4. CE Report CENC-1849, "Evaluation of Calvert Cliffs Reactor Vessel Potential Wear of Bottom Head Clad Due to Loose Pump Bolt," December 16, 1988
5. CE Letter CSE-92-262, "Evaluation of Reactor Vessel Closure Head Stud Elongation for BGE Calvert Cliffs Unit 1," CR-9417-CSE92-1108, Revision 0, July 1, 1992
6. CCNPP Alloy 600 Program Plan, Revision 1, November 1996
7. Letter from Mr. J. T. Wiggins (NRC) to Mr. G. C. Creel (BGE), dated July 21, 1989, "NRC Region I Combined Inspection Report Nos. 50-317/89-06 and 50-318/89-06"
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9. Southwest Research Institute, "1986 Inservice Examination of Selected Class 1 and Class 2 Components and Systems of Calvert Cliffs Nuclear Power Plant, Unit 1," April 1987
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11. "CCNPP Low Temperature Overpressure Protection (LTOP) Controls Report," Revision 0, November 1995
12. CCNPP Procedure EN-1-214, "Low Temperature Overpressure Protection," Revision 0, March 30, 1995
13. CCNPP Component Level Scoping Results, Control Rod Drive Mechanism and Electrical System, Revision 2, May 1995
14. CCNPP Procedure MN-3, "Pressure Boundary Codes and Special Processes Program," Revision 1
15. Inservice Inspection Program Plan for the Second Inspection Interval for Calvert Cliffs Nuclear Power Plant Units 1 & 2, Southwest Research Institute Project 17-1168, November 1987, Revision 0, Change 6, November 20, 1996
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17. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for In-Service Inspection of Nuclear Power Plant Components," 1983 Edition with Addenda through Summer 1983
18. CCNPP Procedure MN-3-301, "CCNPP Boric Acid Corrosion Inspection Program," Revision 1, December 15, 1994
19. CCNPP Procedure QL-2-100, "Issue Reporting and Assessment," Revision 4, January 2, 1996

20. CCNPP Procedure RV-62, "Reactor Vessel Stud, Nut and Washer Cleaning and Inspection," Revision 14, December 23, 1996

21. CCNPP Procedure RV-22, "Reactor Vessel Head O-Ring Replacement," Revision 12, October 24, 1996

22. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 29, 1994, Licensee Event Report 94-004, Revision 01, "Excessive Corrosion of Incore Instrumentation Flange Components"

23. CCNPP Procedure RV-85, "Reactor Vessel ICI Flange Cleaning and Inspection," Revision 2, October 4, 1995

24. Electric Power Research Institute, "PWR Reactor Pressure Vessel License Renewal Industry Report, Revision 1," July 199436

25. CCNPP Fatigue Monitoring Program, Volumes 1 and 2, CE-NPSD-634-P, April 1992

26. ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition with Addenda through Winter 1967

27. CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," Revision 0, February 28, 1996

28. "CCNPP Fatigue Monitoring Report for 1996," Final Report for 1996 generated by CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring"

29. CE Owners Group Report CE-NPSD-634-P, "Fatigue Monitoring Program for CCNPP Units 1 & 2," April 1, 1996

30. Structural Integrity Associates, Inc., SIR-96-006, "Cycle Counting and Cycle-Based Fatigue Report for CCNPP Units 1 and 2," February 21, 1996

31. CCNPP Engineering Standard ES-020, "Specialty Input Screens for the Engineering Service Process," Revision 1, May 1, 1996

32. CCNPP Engineering Service Package, ES199600182-000, "Revise Technical Manual 12017-074 for Tensioning and Detensioning Sequence of RPV Head Studs," Revision 0, February 13, 1996

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35. Title 10 of the Code of Federal Regulations (CFR) Part 50

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37. Electric Power Research Institute, "CCNPP Life Cycle Management/License Renewal Program-Reactor Pressure Vessel Evaluation," April 1995

38. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated June 20, 1997, "Resubmittal of Request for Approval: Revision to Reactor Vessel Surveillance Capsule Withdrawal Schedule"

39. Letter from Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated July 21, 1995, Request for Approval of Updated Values of Pressurized Thermal Shock (PTS) Reference Temperatures (RT_{PTS}) Values (10 CFR 50.61)

40. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated November 29, 1993, "Request to Use Plant-Specific Data for Reactor Vessel Fracture Toughness Analysis"

41. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated July 24, 1995, "Response to Generic Letter 92-01, Revision 1, Supplement 1: Reactor Vessel Integrity"

42. Letter from Mr. D. G. McDonald, Jr. (NRC) to Mr. R. E. Denton (BGE), dated January 2, 1996, "Updated Values for Pressurized Thermal Shock Reference Temperatures - Calvert Cliffs Nuclear Power Plant Unit Nos. 1 and 2," and attached NRC Safety Evaluation Report Pressurized Thermal Shock Evaluation

43. Letter from Mr. M. L. Boyle (NRC) to Mr. R. E. Denton (BGE), dated July 29, 1994, "NRC Safety Evaluation Report (SR) for BGE Request for Approval to Use Plant-Specific Data for Reactor Vessel Fracture Toughness Analysis, CCNPP Unit 1"

44. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), dated August 1, 1996, "Closeout for BGE Response to Generic Letter 92-01, Revision 1, Supplement 1, for the Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2"

45. NRC Memorandum from Mr. J. R. Strosnider to Mr. A. C. Thadani, dated May 5, 1995, "Assessment of Impact of Increased Variability in Chemistry on the RT_{PTS} Value of PWR Reactor Vessels"

46. CEOG Final Report; CE-NPSD-1053, "Results of Fracture Toughness Testing of Unirradiated Linde 1092 RPV Welds - Phase 1," November 1996

47. NRC Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and other Vessel Closure Head Penetrations," April 1, 1997

4.3 Reactor Vessel Internals

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Reactor Vessel Internals (RVI) System. The RVI System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

4.3.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Normally in the IPA process, component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. This scoping is to determine components subject to aging management review (AMR) and begins with a listing of passive intended functions. Then the component types would be dispositioned as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report. For the RVI, a slightly different approach was used for component level scoping.

Section 4.3.1.1 presents the results of the system level scoping. Section 4.3.1.2 discusses the approach used for component level scoping of the RVI. Section 4.3.1.3 presents the results of scoping to determine which components were subject to an AMR.

Historical operating experience, judged to be pertinent, is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently-assigned, cognizant CCNPP personnel.

4.3.1.1 System Level Scoping

This section begins with a description of the system, which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

<u>System Description/Conceptual Boundaries</u>

When the RVI System was scoped, it included the reactor core and the RVI structures, which together provide the heat source and direct the flow of coolant through the reactor vessel. The system also included reactor component handling equipment. [Reference 1, Table 1, System 84]

The major components of the reactor core are 217 fuel assemblies and 77 control element assemblies (CEAs, also called the control rods). The major components of the RVI structures are the core support barrel (CSB), the lower core support structure (including the core shroud [CS]), and the upper guide structure (UGS) (including the 65 CEA shrouds and incore instrumentation [ICI] guide tubes). The reactor component handling equipment includes the reactor vessel head lifting rig, the RVI lifting rigs, and the surveillance capsule retrieval tool. [Reference 1, Table 1, System 84]

The reactor coolant enters the upper section of the reactor vessel, flows downward between the inside of the reactor vessel wall and the outside of the CSB, passes through the flow skirt (also called the baffle), and into the lower plenum. The coolant then flows upward through the RVI and the reactor core removing heat from the fuel rods in the fuel assemblies, and exits the reactor vessel. [Reference 2, Section 3.1]

The reactor's fuel assemblies are arranged to approximate a right circular cylinder with an equivalent diameter of 136 inches and an active height of 136.7 inches. Each fuel assembly consists of 176 rods (pins) and five guide tubes. The pins contain fuel or neutron poison materials. An assembly is held together by spacer grids, and top and bottom end fittings. Lateral support and positioning of the fuel rods within an assembly is provided by leaf spring spacer grids welded to the five full-length guide tubes. The guide tubes provide channels to guide CEAs over their entire length and also form the longitudinal structure of the assembly. In selected fuel assemblies, the central guide tube houses ICI. [Reference 2, Section 3.1]

The RVI are designed to: 1) support and orient the fuel assemblies and CEAs; 2) absorb the CEA dynamic loads and transmit these and other loads to the reactor vessel flange; 3) direct reactor coolant flow through the reactor core; and 4) support and orient ICI. [Reference 3, Section 1.1.1]

Section 3.3.3 of the Updated Final Safety Analysis Report (UFSAR) provides a description of the RVI structures. Figures 3.3-1, 3.3-6, 3.3-11, 3.3-13, and 3.3-14 of the UFSAR depict components of the RVI. Table 4-10 of the UFSAR identifies that the RVI are constructed of Type 304 stainless steel and nickel-chromium-iron (Ni-Cr-Fe) alloy steels. These materials were chosen during the design effort since they had shown satisfactory performance in operating reactor plants. [Reference 2, Section 4.1.4.2.1]

The major support member of the RVI is the core support assembly, which consists of the CSB, the lower core support structure, and the CS. The core support assembly is supported by the upper flange of the CSB, which rests on a ledge in the reactor vessel flange. The lower flange of the CSB supports and positions the lower core support structure, which consists of a core support plate (CSP), vertical columns, horizontal beams, and an annular skirt. The weight of the core is supported by the CSP, which transmits the load through the columns to the beams to the skirt to the lower flange of the CSB. The CSP provides support and orientation for the fuel assemblies. The CS, which provides lateral support for the peripheral fuel assemblies, is also supported by the CSP. The lower end of the CSB is restrained radially by six CSB snubbers. [Reference 2, Section 3.3.3.1] The core support assembly normally remains in the reactor vessel during refueling.

The UGS assembly consists of the upper support plate, 65 CEA shrouds, a fuel assembly alignment plate, and a hold-down ring (HDR). The UGS assembly aligns and laterally supports the upper end of the fuel assemblies, maintains the CEA spacing, prevents fuel assemblies from being lifted out of position during a severe accident condition, and protects the CEAs from the effect of coolant cross-flow in the upper plenum. The UGS is handled as a unit and is removed during refueling to gain access to the fuel assemblies in the reactor core. [Reference 2, Section 3.3.3.6]

Operating experience for components of the RVI includes two events that had the potential for a system-wide failure due to an age-related degradation mechanism (ARDM). The first event occurred at another reactor plant and the second occurred at CCNPP. The first event caused one change to one RVI component at CCNPP, the HDR. To date there has been no identified aging effect from the second event, and none is expected.

The event at another plant that was relevant to the CCNPP RVI demonstrates sharing of operating experience and lessons-learned based on specific experience from other pressurized water reactors (PWRs) supplied by Combustion Engineering, Inc. (CE). It is also indicative of the broader sharing of operating event information based on industry-wide experience with water-cooled reactors, and based on experience applicable to just PWRs. Concerns with components at one reactor have generally been considered for all other reactors through cooperative event evaluation efforts.

Early operation of CE's PWRs led to the introduction of a more substantial HDR in the CCNPP units. Originally, CE supplied a component called an expansion compensating ring with their RVI systems. This ring was to preload the UGS against the CSB flange and thereby preload that flange against the vessel support ledge. At the Palisades Plant in the early 1970s, operating experience showed that the expansion compensating ring provided inadequate clamping force on the RVI and would not prevent their movement under normal operating hydraulic loads. This movement resulted in rocking of the RVI and wear of the support ledge in that vessel.

Also around that time, CE determined that irradiation induced growth of zircalloy fuel rods, and grid cage guide tubes may not have been adequately accounted for in the original design. Together, these findings caused CE to review their system's flow loadings on the RVI, the space available for fuel assemblies, and the impact on the expansion compensating ring for the RVI.

The result was a replacement of CE's original design for the expansion compensating ring with one providing increased force to prevent motion and resulting wear. Calvert Cliffs Unit 1 started operations with the redesigned expansion compensating ring and with a spacer shim to accommodate CE's new growth projections for the length of the fuel assemblies.

By the end of Unit 1's first cycle of operation, CE had again redesigned the expansion compensating ring, this time to be the current design of the HDR, which has a larger structural cross-section and develops more preload when the closure head is installed. During the first refueling outage, the Unit 1 expansion compensating ring was removed and replaced by a HDR. Unit 2 started operations after the design of the HDR was available and has always used a HDR and shim. [Reference 4] The HDR design has been effective in eliminating wear, and no other HDR problems have been reported. [Reference 5, Section 5.2.1.3]

The second operating event with the potential for a system-wide failure due to an ARDM was injection of air into the Reactor Coolant System (RCS) and, thus, into the RVI. In 1979, a leaking valve in the Chemical Volume and Control System allowed air to enter the RCS for several weeks following an ion exchanger resin transfer. The injected oxygen depleted the normal hydrogen inventory, which caused crud deposits to collect on the hot surfaces of the core and boron was deposited with the crud. The results were observed changes in the pressure drop across the core (delta-P) and changes to the core's power distribution. The deposits were removed with hydrogen peroxide and plant operating conditions returned to normal during subsequent operations. Procedural modifications included more effective isolation of the Chemical Volume and Control System and use of nitrogen instead of air to eliminate further incidents of this type. [Reference 6]

This operating event is considered to have the potential for an aging impact on the RVI at CCNPP due to industry operating experience with irradiation assisted stress corrosion cracking (IASCC) at boiling water reactors (BWRs). The oxygen concentration in the reactor coolant for BWRs is much higher than for PWRs, and the continuous operation with more oxygen in the coolant is believed to be a major factor in the cracking of RVI components at BWRs. [Reference 7, Section 4.3.2]

In reviewing the historical record on operations at CCNPP, the air intrusion event was identified as a short time when oxygen levels were temporarily above normal concentrations while at power. The relationship between a one-time event and an ARDM occurring much later in a plant's life is not well understood, but in this case, the cause and effect relationship is not likely to be strong. Boiling water reactors have always operated at relatively higher oxygen concentrations and, in contrast, the one-time event at CCNPP represents an exposure duration to higher oxygen concentrations that is but a small fraction of the typical exposure duration for BWR RVI at full power. Since BWRs experience IASCC after many years of operation with relatively high oxygen concentrations, the difference in exposure history to elevated oxygen concentrations should have minimal effect on Unit 1's susceptibility to this aging mechanism.

In support of this position, note that periodic inservice inspections (ISIs) are performed on the CCNPP RVI and have been since the start of operations. The inspections meet the examination type and frequency requirements in the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). Examinations performed after the event have not identified any failures or indications of adverse conditions resulting from this air intrusion event at CCNPP. Also, continuing evaluation of industry-wide events will ensure timely consideration of IASCC-related developments at other plants, and their implications for CCNPP.

System Interfaces

The reactor core and the RVI interface with three other systems. The fuel assemblies and CEAs interface with the Control Element Drive Mechanisms and Electrical System since the CEAs are driven by the control element drive mechanisms. [Reference 1, Table 1, System 84; Reference 2, Section 3.3.4.1] The RVI interface with the Reactor Pressure Vessel System since the vessel supports and positions the RVI. Both the reactor core and the RVI interface with the RCS, and are completely immersed in the RCS environment.

Section 4.1 of the BGE LRA evaluates the RCS and credits primary chemistry control as an Aging Management Program to manage plausible aging of components in the RCS. Because this chemistry program is credited for the RCS, and because the RVI are totally immersed in the RCS environment, the demonstration of the primary chemistry control program as an Aging Management Program is not repeated in this section. Instead, the aging evaluation for the RVI credits the chemically treated and controlled, demineralized water environment provided by the RCS as an initial condition of this evaluation. [Reference 3, Section 4.2.3]

The reactor component handling equipment within the scope of license renewal and their interfaces with other systems are addressed with the Fuel Handling Equipment and Other Heavy Load Handling Cranes, which is discussed in Section 3.2 of the BGE LRA.

System Scoping Results

System level scoping for the RVI System addressed the pieces of equipment included in the system's conceptual boundaries. However, only the RVI are evaluated in this section of the BGE LRA; the other equipment is either addressed in a different section of the BGE LRA or is not within the scope of license renewal.

In the reactor core, the fuel assemblies have functions during design basis events that make the assemblies within the scope of license renewal. [Reference 1, Table 2] However, the assemblies are replaced at regular intervals based on the fuel cycle of the plant. Since the assemblies are short-lived components, their aging is not discussed further below. The CEAs in the core are discussed with the Control Element Drive Mechanisms and Electrical System in Section 4.2 of the BGE LRA. [Reference 3, Section 1.1.1]

The reactor vessel head lifting rig is discussed with the Fuel Handling Equipment and Other Heavy Load Handling Cranes in Section 3.2 of the BGE LRA. The RVI lifting rigs and the surveillance capsule retrieval tool are not installed components and are not within the scope of license renewal. [Reference 3, Section 1.1.1]

The RVI were determined to be within the scope of license renewal during the system level scoping based on 10 CFR 54.4(a)(1). [Reference 3, Section 1.1.1] The intended function of the RVI was determined to be to:

- Provide structural support for the fuel assemblies, CEAs, and ICI so that they maintain the configuration and flow distribution characteristics assumed in the UFSAR Chapter 14 analyses. [Reference 3, Section 1.1.3]

The RVI will safely perform their intended function during normal operating and design basis event conditions. The RVI are designed to safely withstand forces due to deadweight, handling, temperature and pressure differentials, flow impingement, vibration, and seismic acceleration. [Reference 2, Section 3.1] All components are considered Category I for seismic design. The structural components satisfy stress values given in the ASME Code, Section III. The RVI design provides limits for deflection where this is functionally required. The limitations on stresses or deformations are employed to ensure capability of a safe and orderly shutdown in the combined event of an earthquake and major loss-of-coolant accident. For RVI structures, the stress criteria are given in Table 3.2-1 of the UFSAR. [Reference 2, Section 3.2.3.4]

4.3.1.2 Component Level Scoping

Component level scoping and component pre-evaluation were not applied to the RVI before the aging evaluation to determine which components were subject to an AMR. Instead, all components of the RVI were initially included in the scope of the AMR. During the AMR, some components were determined not to be within the scope of license renewal since they are not required for the RVI to perform their intended function. [Reference 3, Section 1.1.1]

4.3.1.3 Components Subject to Aging Management Review

This subsection describes the device types within the RVI, and those which are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the device types as either evaluated in other sections of the BGE LRA, or evaluated for aging management in this section.

Passive Intended Functions

In accordance with the CCNPP IPA Methodology Section 5.1, the following intended function of the RVI was determined to be passive. [Reference 3, Section 1.1.1]

- Provide structural support for the fuel assemblies, CEAs, and ICI so that they maintain the configuration and flow distribution characteristics assumed in the UFSAR Chapter 14 analyses. [Reference 3, Section 1.1.3]

Device Types Subject to Aging Management Review

Because site database information for the RVI does not contain distinct equipment identifications for each component, a listing of component names was developed specifically for this task, using controlled plant drawings as the source of information. The 17 major RVI assemblies were designated as the device types, and the components of these major assemblies were treated as the individual components of the system. [Reference 3, Section 1.1.1] A list of the 17 device types for the RVI that were evaluated in the AMR is provided in Table 4.3-1. [Reference 3, Section 1.1.2]

As shown in the table, not all device types of the RVI are evaluated in this section of the BGE LRA. The explanations for these device types is as follows:

- The flow baffle is a structure inside of the reactor pressure vessel, but it is welded to supports that are welded to the inside of the vessel wall. The flow baffle is shown as the flow skirt in UFSAR Figure 3.1-1. Since it is welded to the vessel wall, the baffle is evaluated with other vessel components in the Reactor Vessel/Control Element Drive Mechanism System in Section 4.2 of the BGE LRA.
- The CSB snubber and snubber bolts are physically bolted to the CSB, but work with the core stabilizing lugs that are welded to the vessel wall. Together these components limit flow-induced vibrations in the CSB. The design of the CSB snubber assembly is shown in UFSAR Figure 3.3-12. Due to this mating-part relationship, the snubber and snubber bolts are evaluated with the lugs in Section 4.2 rather than in this section of the BGE LRA.
- Some components were found to be outside the scope of license renewal. For the ICI thimbles device type, the only component that is within the scope of license renewal is the ICI flange which provides a pressure retaining boundary for the RCS. Because of this function, the ICI flange is evaluated in Section 4.2 of the BGE LRA with reactor pressure vessel components that have the same function. [Reference 3, Section 1.1.2]

Although none of the RVI components are currently subject to replacement, BGE may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

TABLE 4.3-1
DEVICE TYPES REQUIRING AMR

No	Device Type Name	Addressed in License Application Section
1	CEA Shroud and Bolts (CEASB)	This Section
2	CEA Shroud Extension Shaft Guides (ESG)	This Section
3	CS	This Section
4	Core Shroud Tie Rod and Bolts (CSTR)	This Section
5	CSB	This Section
6	Core Support Barrel Alignment Key (CSBA)	This Section
7	Core Support Barrel Snubber and Snubber Bolts	Section 4.2
8	Core Support Columns (CSC)	This Section
9	CSP	This Section
10	Flow Baffle	Section 4.2
11	Fuel Alignment Pins (FAP)	This Section
12	Fuel Alignment Plate/Guide Lug Insert (FP)	This Section
13	HDR	This Section
14	ICI Thimble Support Plate (ITSP)	This Section
15	ICI Thimbles	Section 4.2
16	Lower Support Structure Beam Assembly (LSSBA)	This Section
17	Upper Guide Structure Support Plate (UGSP)	This Section

Thus, components for 3 of the 17 device types in the RVI within the scope of license renewal are discussed in the Reactor Pressure Vessel Section of the BGE LRA. The remainder of this section evaluates ARDMs for the other 14 device types listed in Table 4.3-1.

4.3.2 Aging Management

The list of potential ARDMs for the RVI is given in the first column of Table 4.3-2. [Reference 3, Table 4-1] The plausible ARDMs for each device type are identified by a check mark (✓) in the appropriate column. [Reference 3, Table 4-3] As shown in the table, the ITSP is the only device type for which no plausible ARDM was identified.

For efficiency in presenting the results of the evaluations, devices types affected by an ARDM are grouped together into seven groups. These groups are easily identified by moving across each ARDM's row in the table. Where a device type's column has a group number, that device type is in the group.

The discussions below regarding an ARDM are applicable to all devices types in the group. For some device types, not all components are susceptible to a particular ARDM. When this is the case, a note for the exception is provided in the table to explain which components are, or are not, susceptible.

TABLE 4.3-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE REACTOR VESSEL INTERNALS

ARDMs	Device Types for Which ARDM Is Plausible														Not Plausible for RVI
	CEASB	ESG	CS	CSTR	CSB	CSBA	CSC	CSP	FAP	FP	HDR	ITSP	LSSBA	UGSP	
Wear		✓ (1)(a)			✓ (1)(b)	✓ (1)			✓ (1)	✓ (1)(c)	✓ (1)			✓ (1)	
Neutron Embrittlement	✓ (2)(d)		✓ (2)	✓ (2)	✓ (2)(e)		✓ (2)	✓ (2)	✓ (2)	✓ (2)			✓ (2)		
Low Cycle Fatigue			✓ (3)(f)	✓ (3)(g)			✓ (3)	✓ (3)							
Thermal Aging	✓ (4)(h)						✓ (4)								
Stress Relaxation	✓ (5)(i)			✓ (5)(j)											
Stress Corrosion Cracking (SCC)/ Intergranular SCC (IGSCC)/ Intergranular Attack	✓ (6)(k)														
High Cycle Fatigue	✓ (7)(l)														
Erosion															X
Erosion/Corrosion															X
General Corrosion/ Uniform Attack															X
Hydrogen Damage															X

TABLE 4.3-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE REACTOR VESSEL INTERNALS

ARDMs	Device Types for Which ARDM Is Plausible														Not Plausible for RVI
	CEASB	ESG	CS	CSTR	CSB	CSBA	CSC	CSP	FAP	FP	HDR	ITSP	LSSBA	UGSP	
IASCC															X
Pitting/Crevice Corrosion															X

✓ Indicates plausible ARDM determination
(#) Indicates the group number that the device type is in for a plausible ARDM.
( ) Indicates that not all components of a device type are susceptible to the ARDM. The notes below clarify the exceptions.

	Device Type	Components
(a)	ESG	guides only
(b)	CSB	upper flange only
(c)	FP	guide lugs and guide lug inserts only
(d)	CEASB	except spanner nuts and tabs
(e)	CSB	except upper flange
(f)	CS	plates and ribs only
(g)	CSTR	tie rods, nuts, and set screws only
(h)	CEASB	shroud assembly tubes only
(i)	CEASB	shroud bolts only (also called the CEA shroud socket-head cap screws)
(j)	CSTR	tie rods, nuts, and set screws only
(k)	CEASB	shroud bolts only
(l)	CEASB	except spanner nuts, tabs, shroud bolts, retention blocks, and shaft retention pins.

A notable ARDM that is considered not plausible at CCNPP is IASCC. As noted earlier, the IASCC phenomenon has been experienced at BWRs where oxygen levels in the RCS are substantially higher than in PWRs. Although irradiation leading to SCC of austenitic stainless steels has been experienced in water environments with relatively high oxygen concentrations, it has also been hypothesized that IASCC may be a potentially significant ARDM for certain RVI components in PWRs. The most susceptible components would be those where the neutron fluence is $>5x10^{20}$ n/cm^2 for materials with low stress levels (<10 ksi), and $>1x10^{20}$ n/cm^2 for materials with moderate to high stress levels (>10 ksi). [Reference 3, Attachment 7, IASCC] A similar ARDM has been observed in PWR control element drive mechanism tips where very high strain is applied at a very low strain rate in a high fluence field. [Reference 3, Attachment 6s, Code 22]

However, for controlled water chemistry environments where the oxygen concentration is normally less than 5 ppb and the halogen concentration is normally less than 150 ppb, there is no conclusive evidence that demonstrates IASCC should be considered a plausible ARDM for austenitic stainless steels at low stress levels. [Reference 3, Attachment 7, IASCC] Irradiation assisted stress corrosion cracking has not been observed for components with the temperature, oxygen, and radiation levels present for the CCNPP RVI, either in operating plants or in laboratory tests. Therefore, this ARDM is considered not plausible at CCNPP and no specific aging management activity for IASCC is warranted at this time. [Reference 3, Attachment 6s, Code 22]

Below are the evaluation results for the plausible ARDMs. For each group, there is information on the device types that form a group, the materials and environment pertinent to the ARDM for the group of device types, the aging effects, the methods to manage aging, and the aging management program(s). The ARDMs are addressed in the order shown in Table 4.3-2: wear, neutron embrittlement, low cycle fatigue, thermal aging, stress relaxation, SCC, and high cycle fatigue.

Group 1 (Wear) - Device Types, Materials, and Environment

Table 4.3-2 shows that wear is plausible for seven device types in the RVI. This group of device types includes: ESG (guides only), CSB (upper flange only), CSBA, FAP, FP (plate, guide lugs, and guide lug inserts only), HDR, and UGSP. The surfaces of these components for which wear is a plausible ARDM are accessible for visual examination. [Reference 3, Attachment 6s, Code D]

These components are constructed of various stainless and alloy steels (American Society for Testing Materials [ASTM] A-182, A-240, and A-276). [Reference 3, ESG, CSB, CSBA, FAP, FP, HDR, and UGSP, Attachment 3s] Stellite was added to the wear surfaces of the FP guide lugs and guide lug inserts. [Reference 3, FP, Attachment 3]

The operating environment for the components of the RVI pertinent to wear is immersion in the RCS flow which results in the possibility of flow-induced vibrations. Table 3.5-1 of the UFSAR provides the design values for the thermal and hydraulic parameters at full power, and shows that the normal RCS pressure is 2250 psia. [Reference 3, Section 3.5.1] However, the RVI are not part of the RCS pressure boundary and do not withstand a pressure loading of 2250 psia. Rather, these components withstand various local pressure forces and loadings from the flow of the coolant through the vessel from the inlet to the outlet nozzles. During normal operations, there is a relatively low fluid velocity through the RVI. [Reference 3, Attachment 6s, Code 13] The low fluid velocity minimizes flow-induced vibrations and corresponding wear on component surfaces.

Another aspect of operations that is pertinent to wear is the assembly and disassembly of the RVI for refueling as relative movement between parts occurs during these activities.

Group 1 (Wear) - Aging Mechanism Effects

Wear is considered plausible for RVI components that touch while experiencing relative motion. Wear may occur on surfaces of components that are in contact (e.g., mating flanges) or surfaces that are in close proximity to each other that come into contact and experience intermittent relative motion (e.g., rub together due to flow-induced vibration). Wear may also occur in clamped joints, where relative motion is not intended but happens due to a loss of clamping force and flow-induced vibration. Reactor vessel internals components that are in contact, in close proximity but not designed to touch, or joints that are bolted, keyed, pinned, or press-fit together are potential areas for wear to occur. [Reference 3, Attachment 7, Wear] The effect of wear is a loss of surface metal from the affected material. [Reference 3, Attachment 6s, Code D]

Wear has occurred in PWRs designed by all three U. S. suppliers. [Reference 5, Section 5.3] As discussed in Section 4.3.1.1 above, wear occurred at the CE-designed Palisades Plant. In that case, the wear resulted in replacement of the expansion compensating ring with the HDR at CCNPP Units 1 and 2.

Group 1 (Wear) - Methods to Manage Aging

Mitigation: The potential effects of wear during operation were addressed during the design of the RVI through appropriate tolerances, adequate clearances, sufficient material thickness, choices of component materials, and the use of special surface finishes. Stellite hardfacing was designed into the surfaces where wear was expected to be a concern for RVI components, (i.e., on the FP guide lug and guide lug inserts). Because wear was accounted for in design, programs are not needed for mitigation during operations.

Discovery: Wear can be discovered when the reactor vessel is opened and RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc.

Group 1 (Wear) - Aging Management Programs

Mitigation: There are no CCNPP programs credited for mitigation of wear for the RVI.

Discovery: The Inservice Inspection Long Term Plan governs the conduct of ASME Code Section XI inspections. [Reference 3, Attachment 10] This Plan invokes the requirements of Section XI of the ASME Code, 1983 Edition through Summer 1983 Addenda, and requires inspections of the components in the RVI. [Reference 8, Section 1.2.1]

The purpose of the ISI Program is to control the methods and actions for ensuring the structural and pressure-retaining integrity of safety-related nuclear power plant components in accordance with the rules of ASME Code Section XI. [Reference 9, Section 3.0D] The ISI Program ensures that Class 1, 2, 3, and

MC components are inspected as required by 10 CFR 50.55a and ASME Code Section XI. The type of inspection, the required frequency for the inspection, the components to be inspected, and the acceptance criteria are established in ASME Code Section XI. [Reference 3, Attachment 2, Section XI ISI] The RVI components are Class 1 per ASME Code Section XI. [Reference 10, Subsection IWB]

The scope of the existing ISI Program for the RVI applies to components identified in ASME Code Section XI, Subsection IWB. [Reference 11, Section 1.2A] The ISI Program requirements and the developmental and performance references are provided in Reference 11. Under the ISI Program, the procedural steps involve nondestructive examinations of components. A nondestructive examination (NDE) is an examination and measurement of material properties and conditions to assess a component's fitness for intended use without damaging or impairing component serviceability. [Reference 11, Section 3.0.M]

Inservice inspection requirements in ASME Code Section XI provide for visual examination of accessible areas of the vessel interior, including the space above and below the reactor core that are made accessible for examination by removal of components during refueling outages. The requirements include visual examination of accessible surfaces of the core support structures, and these must be removed from the reactor vessel for examinations. [Reference 10, Table IWB-2500-1]

American Society of Mechanical Engineers Code Section XI ISI visual examinations of the RVI components determine the general mechanical and structural conditions of components and their supports, such as the presence of loose parts, debris, abnormal corrosion products, wear, erosion, corrosion, and the loss of integrity at bolted connections. Examinations may also be used to determine structural integrity, i.e., measure clearances; detect physical displacements; or determine the structural adequacy of supporting elements, the condition of connections between load-carrying structural members, or the tightness of bolting. [Reference 10, IWA-2213, Visual Examination VT-3]

The ASME Code provides requirements for timely correction of relevant abnormal conditions. [Reference 10, IWA-4130 Repair Program] Since wear between two accessible surfaces subject to relative motion is readily detectable by visual examination before the effects of wear begin to compromise the structural integrity or function of components, ISI is adequate to manage such effects. [Reference 3, Attachment 8, Wear] The corrective actions taken will ensure that the RVI components remain capable of performing their intended functions under all current licensing basis (CLB) conditions.

The ISI Program has been used to examine the accessible surfaces of the RVI in previous refueling outages. A review of the current ISI Program implementing procedures showed that the procedures will be enhanced if modified to specifically identify each component of the RVI which relies on this program for aging management for license renewal. [Reference 3, Attachment 2, Section XI ISI]

The ISI Program is subject to internal and independent assessments, and is recognized through these assessments as performing highly effective examinations and aggressively pursuing continuous improvements. Baltimore Gas and Electric Company monitors industry initiatives and trends in the area of ISI and NDE. The program is also subject to frequent external assessments by Institute of Nuclear Power Operations, NRC, and others.

Operating experience relative to the ISI Program at the CCNPP has been such that no site specific problems or events have occurred that required changes or adjustments. The program has been effective in its function of performing examinations required by ASME Code Section XI.

Specific to the visual examinations for wear of the RVI, the ISI Program has been used in previous refueling outages to examine accessible surfaces. This operating experience shows a consistent ability to identify surface indications, e.g., scratches and gouges, for evaluation against acceptance criteria. For example, the 1991 examination records for the Unit 2 CSBA identify that gouges found during the visual examinations were dispositioned as minor indications such that keyway serviceability is not affected. [Reference 12] The ISI Program records show that the gouges were again found in the subsequent required examinations performed in 1993, and the report states that the gouges were noted in previous examinations and accepted as is. [Reference 13] The minor nature of these indications, and the repeatability in finding them, provides evidence of the effectiveness of the ISI Program to identify the effects of wear.

Group 1 (Wear) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of wear on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Wear is plausible for RVI components and results in material loss which could lead to loss of intended function.
- The CCNPP ISI Program provides for periodic visual examinations of accessible surfaces of RVI components.
- Examinations will be performed, and appropriate corrective action will be taken if significant wear is discovered.

Therefore, there is reasonable assurance that the effects of wear will be managed in order to maintain the structural integrity of RVI consistent with the CLB during the period of extended operation.

Group 2 (Neutron Embrittlement) - Device Types, Materials, and Environment

Table 4.3-2 shows that neutron embrittlement is plausible for nine device types in the RVI. This group of device types includes: CEASB (except the spanner nuts and tabs), CS, CSTR, CSB (except the upper flange), CSC, CSP, FAP, FP, and LSSBA.

These components are constructed of various stainless and alloy steels (ASTM A-182, A-193, A-194, A-240, A-269, A-276, A-351, A-451, and A-479; and Aerospace Material Specification (AMS) 5735 iron base superalloy A-286). [Reference 3, CEASB, CS, CSTR, CSB, CSC, CSP, FAP, FP, and LSSBA, Attachment 3s]

The environment pertinent to neutron embrittlement is the high energy neutron fluence experienced during normal operations. The closer a component is to the core, the larger the integrated exposure to high energy neutrons will become. Another pertinent aspect of the environment is immersion in the RCS rather than forming part of the RCS pressure boundary. The loads on the components from the coolant flow are much less than if they were RCS pressure retaining components.

Group 2 (Neutron Embrittlement) - Aging Mechanism Effects

Neutron embrittlement is considered plausible for RVI components exposed to high energy neutrons, and can cause changes in properties of stainless steel and nickel-base alloys used in these components. The extent of neutron embrittlement is a function of both temperature and neutron fluence. At reactor operating temperatures, neutron embrittlement is plausible for device types that would experience high energy neutron flux. While the components nearest the core experience such high fluxes, the fluence levels are not sufficient to cause appreciable neutron embrittlement of components located above the reactor vessel nozzles. [Reference 3, CEASB, ESG, CSB, CSBA, ITSP, and UGSP, Attachment 6s, Code 23]

The effect of neutron embrittlement is a loss of fracture toughness of the affected material (i.e., a lower resistance to crack initiation), leading to parts, bolting, or fasteners that are loose, missing, cracked, or fractured. [Reference 3, CEASB, CS, CSTR, CSB, CSC, CSP, FAP, FP, and LSSBA, Attachment 6s, Code G] These effects are the precursors to the loss of the intended function for these components.

No instances of degradation of RVI for PWRs have been recorded which have definitely been attributed to neutron embrittlement. [Reference 7, Section 4.1.2]

Group 2 (Neutron Embrittlement) - Methods to Manage Aging

Mitigation: The effects of neutron embrittlement for the RVI components could be mitigated by lowering the neutron flux from the reactor core that reaches these components through the use of low-leakage core designs. This approach is not practical for the components of the RVI which completely surround the core.

Discovery: The effects of neutron embrittlement can be discovered when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components that are loose, missing, cracked, or fractured would be readily observable by visual examination.

Loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 2 (Neutron Embrittlement) - Aging Management Programs

Mitigation: Although CCNPP's 24-month core designs use a low leakage configuration, no aging management credit for mitigating neutron embrittlement of the RVI is given to efforts to reduce neutron leakage from the core.

Discovery: American Society of Mechanical Engineers Code Section XI ISI is the existing program credited for aging management of the effects of neutron embrittlement for the components in the RVI. [Reference 3, Attachment 8, Neutron Embrittlement] The purpose, scope, bases, operating experience, etc., for the ISI Program are described above in the subsection, Group 1 (Wear) - Aging Management Programs.

The ISI Program is adequate for control of this ARDM since the precursors of failure of a component's intended function would be parts, bolting, or fasteners that become loose, missing, cracked or fractured, and are readily observable by the required examinations. Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions. As noted above in the subsection, Group 1 (Wear) - Aging Management Programs, the current ISI Program implementing procedures will be modified to specifically identify each component of the RVI which rely on this program for aging management for license renewal. [Reference 3, Attachment 2, Section XI ISI]

Group 2 (Neutron Embrittlement) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of neutron embrittlement on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Neutron embrittlement is plausible for RVI components and results in a loss of fracture toughness of the affected material (i.e., a lower resistance to crack initiation), leading to loose, missing, cracked, or fractured parts, bolting, or fasteners.
- The CCNPP ISI Program provides for periodic examinations of accessible surfaces of RVI components.
- Visual examinations will be performed, and appropriate corrective action will be taken if precursors to the loss of intended function due to neutron embrittlement are discovered.

Therefore, there is reasonable assurance that the effects of neutron embrittlement will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 3 (Low Cycle Fatigue) - Device Types, Materials, and Environment

Table 4.3-2 shows that low cycle fatigue is plausible for four device types in the RVI. This group of device types includes: the CS (plates and ribs only), CSTR (tie rods, nuts, and set screws only), CSC, and CSP.

These components are constructed of various stainless and alloy steels (ASTM A-193, A-194, A-240, A-351, and A-479). [Reference 3, CS, CSTR, CSC, and CSP, Attachment 3s]

The environment pertinent to low cycle fatigue for the RVI during power generation is chemically treated, demineralized water that increases in temperature from 100°F or less at startup, to approximately 599°F at full power. [Reference 2, Section 4.1.1, Table 4.1] Plant transients subject the RVI to thermal stress during plant heatup, cooldown, and plant trips. However, since the RVI are relatively thin-walled parts and are immersed in the RCS, rather than thicker-walled components needing to withstand RCS pressure, the RCS transients are less severe for the RVI than for pressure retaining components. The pressure loads on the components from the coolant flow around them are much less than if they were RCS pressure retaining components. [Reference 3, Attachment 8, Low Cycle Fatigue] But RVI components that directly surround the reactor core are exposed to intense gamma heating, which leads to higher average temperatures and thermal gradients that induce higher thermal loadings than for other RVI components. [Reference 3, CS, CSTR, CSC, and CSP, Attachment 6s, Code B]

Group 3 (Low Cycle Fatigue) - Aging Mechanism Effects

Fatigue is the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points, and which may culminate in cracks or complete fracture after a sufficient number of fluctuations. The fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure. A component subjected to sufficient cycling with significant strain rates, may develop cracking. The cracks may then propagate under continuing cyclic strains. [Reference 14] Calvert Cliffs has not discovered any low-cycle, fatigue-related failures in the RVI. Also, there have not been occurrences of fatigue damage at other CE PWRs that were identified as low-cycle fatigue failures. [Reference 7, Section 3.3.3; Reference 5, Section 5.3.3]

Plant transients apply cyclical thermal loadings that contribute to low-cycle fatigue accumulation on the RVI. The typical thermal transients of concern for RVI components potentially affected by low-cycle fatigue are changes in gamma heating due to RCS heatup, cooldown, and plant trips. The original design criteria for the RVI were not from the ASME Code, because these plants, like other early PWR plants, were designed before the development of the ASME Code requirements that are specifically applicable to RVI. Such early PWRs had the RVI designed based on criteria specific to the supplier. Although the suppliers used ASME Code Subsection NB as the guideline for development of their criteria, such plants do not have an explicit fatigue design basis. [Reference 7, Section 3.2.1]

However, the principles of similitude apply for identifying the components of these older RVI most susceptible to low-cycle fatigue. A similitude demonstration is based on a number of factors, foremost of which is the similarity of geometry and similarity of component operating history. The most-fatigue-susceptible RVI components have been identified for PWR plants of the three U.S. suppliers using design stress reports and hot functional test data for later plants. These components require further evaluation. [Reference 7, Section 1.4.2]

Low-cycle fatigue is a potential concern for these RVI components because they are nearest the reactor core and reach the highest temperatures. Since the largest plastic strains typically occur at notches, corners, and other geometric discontinuities, the effects of low cycle fatigue would be expected to become evident at such locations of high stress.

The effects of low cycle fatigue would be cumulative fatigue damage of the affected metal due to the cyclic loads applied to the material by gamma heating. The damage would be evident as fatigue cracks in highly stressed regions. Materials are damaged by low cycle fatigue when the cyclic thermal loads are sufficiently high to cause significant plastic deformation of the highly stressed regions. [Reference 3, Attachments 7 and 8, Low Cycle Fatigue]

Group 3 (Low Cycle Fatigue) - Methods to Manage Aging

Mitigation: The most significant thermal transients occur during plant heatup, cooldown, and plant trips. These are temporary modes of operation, which cannot be avoided. As part of general operating practice, plant operations minimize the effects of these transitory operational conditions.

Discovery: As discussed above, low cycle fatigue in PWR RVI was addressed in the similitude demonstrations performed to identify the components most susceptible to low-cycle fatigue. For these components, analysis can be used to determine the susceptibility of a component to low cycle fatigue. [Reference 7, Section 1.4.2]

American Society of Mechanical Engineers Code, Section III, Subsection NG, design rules for fatigue can be used to demonstrate that the effects of fatigue can be managed adequately for the fatigue-critical RVI components. [Reference 7, Section 5.7] The procedures in the Code include an exemption from detailed fatigue analysis for PWR RVI if their specified service loads satisfy certain limitations on severity. If the limits are not met entirely, detailed fatigue evaluation is required. The analysis involves determining the set of design transients associated with service loadings and their frequency of occurrence, and the calculation of the stresses and stress ranges at controlling component locations. [Reference 7, Section 5.7.1]

The Code's fatigue design procedures utilize a design fatigue curve which plots alternating stress range versus the number of cycles to failure. The curve is based on the un-notched fatigue properties of the material, modified by reduction factors that account for various geometric and moderate environmental effects. The fatigue usage factor is defined by Miner's Rule as the summation of the damage over the total number of design basis transient types. The damage for each transient type is given by the ratio of the expected number of cycles of that transient type to the allowable number of cycles for the stress ranges associated with that transient. For ASME Code acceptance, the usage factor calculated in this manner cannot exceed unity (1.0) for the design lifetime of the component. [Reference 7, Sec 4.10.2]

Alternatively, the effects could be discovered when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components susceptible to low-cycle fatigue that have a fatigue crack initiating would be readily observable by visual examination.

The preferred aging management method would be to perform fatigue analyses to estimate the fatigue usage of the components. Current analysis techniques, such as those specified in ASME Code Section III, are capable of predicting the fatigue life of components through calculation of a cumulative usage factor. The fatigue usage factor of a component increases as the number of thermal transients experienced increases. Monitoring the cumulative usage factor over time, based on actual plant data, can be an effective method of predicting end of fatigue life and demonstrating adequacy through the period of extended operation. [References 15 and 16]

Group 3 (Low Cycle Fatigue) - Aging Management Programs

Mitigation: As part of general operating practice, plant operators minimize the severity of transitory operational cycles. Further modification of plant operating practices to reduce the temperature ranges and/or frequencies of thermal transients would unnecessarily place additional restrictions on plant operations.

Discovery: A fatigue analysis will be performed to show that the stress ranges and expected number of transients for these components will be low enough that thermal fatigue will not impair their intended function during the period of extended operation. [Reference 3, CS, CSTR, CSC, and CSP, Attachment 6s, Code B] The stress ranges that cause these RVI components to be more susceptible than others are primarily those caused by the temperatures experienced by these components due to gamma heating from the core.

Calvert Cliffs Units 1 and 2 were both designed before the development of ASME Code requirements specifically applicable to RVI. Since the design was not based on the Code's fatigue analysis procedures, the principles of similitude were applied to identify the fatigue-critical components of the RVI using design stress reports and hot functional test data for later CE plants. The fatigue critical components require further evaluation. [Reference 7, Section 1.4.2]

The Code's fatigue design rules described above will be used to demonstrate that the effects of fatigue can be managed adequately for the RVI components. [Reference 7, Section 5.7] For acceptance under the Code, the cumulative usage factor cannot exceed 1.0.

Based on the service loadings for these components, the analysis is expected to show that the fatigue usage factor will be sufficiently low (0.5 or less) and that no further evaluations will be required for the period of extended operations. However, if the analysis shows a cumulative usage factor greater than 0.5 for any specific components, then further evaluations will be performed. For each such component, the evaluation will either provide justification that the component is bounded by other component(s) already monitored in the Fatigue Monitoring Program, or if not bounded, then the specific components will be added to the Fatigue Monitoring Program. [Reference 3, Attachment 10, Specific Fatigue Analysis]

The Fatigue Monitoring Program already identifies, tracks, and evaluates cumulative fatigue usage of limiting components in the Nuclear Steam Supply System. This existing program has eleven locations selected for monitoring fatigue usage which represent the bounding locations for the effects of thermal transients due to operating cycles. [Reference 17, Section 1.2] If the results of the initial fatigue analysis show that the predicted fatigue usage of a RVI component would warrant (i.e., would exceed 0.5 at the end of the period of extended operation), the component will be added to the Fatigue Monitoring Program for fatigue usage tracking and evaluation.

The detailed fatigue analysis will be performed because there is presently insufficient evidence to conclude that low cycle fatigue is not plausible for these components. However, with no pressure stresses, thinner components, and lower differential temperatures than in piping components of similar materials, it is believed that low cycle fatigue of these RVI components will be shown to be insignificant. [Reference 3, Attachment 8, Low Cycle Fatigue]

If the detailed fatigue usage analysis or subsequent tracking and evaluation does not demonstrate acceptable management of low-cycle fatigue, the effects could be discovered by an examination for fatigue cracks initiating in these RVI components. Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

Group 3 (Low Cycle Fatigue) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of low cycle fatigue on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Low cycle fatigue is plausible for the RVI components and could result in fatigue cracking of the affected metal due to cyclic loads applied to the material.
- A fatigue analysis will determine that low-cycle fatigue will not affect the intended functions of these components during the period of extended operation by showing that the fatigue design basis will be adequate, or that the fatigue usage will be bounded by that of other already monitored components. Alternatively, the fatigue usage for specific RVI components will be tracked and evaluated, or specific components will be examined.

Therefore, there is reasonable assurance that the effects of low cycle fatigue will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 4 (Thermal Aging) - Device Types, Materials, and Environment

Table 4.3-2 shows that thermal aging is plausible for two device types in the RVI. This group includes the CEASB (only the CEA shroud assembly tube) and CSC.

The materials of these two components are cast austenitic stainless steel (CASS). The CEA shroud assembly tubes are ASTM A-451 centrifugally-cast austenitic stainless steel. [Reference 3, CEASB, Attachment 3] The CSC are ASTM A-351 statically-cast austenitic stainless steel. [Reference 3, CSC, Attachment 3]

The environment pertinent to thermal aging is the operating temperature experienced during normal operations. Normal RCS operating temperatures are 548°F for the cold leg and 599.4°F for the hot leg. [Reference 2, Section 4.1.1, Table 4.1]

Group 4 (Thermal Aging) - Aging Mechanism Effects

Thermal aging of concern is embrittlement of components made from CASS and is considered plausible for RVI components constructed of CASS. Thermal aging is time and temperature dependent, and its significance is dependent on the delta ferrite content of the CASS. The maximum rate of embrittlement occurs in the temperature range between 840°F and 930°F; however, thermal embrittlement has been observed at a temperature range as low as 550°F to 650°F. In general, low carbon grades of cast stainless steel are the most resistant to thermal aging, and molybdenum-containing high carbon grades are the most susceptible. Nickel-based alloys are resistant to thermal aging in the temperature range of the RVI. [Reference 3, Attachment 7, Thermal Aging]

The effect of thermal aging is a loss of fracture toughness of the affected metal. [Reference 3, CEASB and CSC, Attachment 6s, Code C] A loss of fracture toughness could lead to loose, missing, cracked, or fractured parts. [Reference 3, CEASB and CSC, Attachment 6s, Code G] These effects are the precursors to the loss of the intended function for these components.

Calvert Cliffs has not discovered any thermal aging-related damage for the RVI. Also, there have not been RVI damage events at other PWRs that were identified as thermal aging failures. [Reference 7, Section 3.3; Reference 5, Section 5.3]

Group 4 (Thermal Aging) - Methods to Manage Aging

Mitigation: The effects of thermal aging could be mitigated by operating below the temperature range where this ARDM occurs, but this is not practical for reactor operations.

Discovery: The impact of thermal aging on CASS material in PWR RVI has been determined to be insignificant if the delta ferrite content of the material is less than certain thresholds. Thermal aging is potentially significant for: (1) centrifugally-cast parts with a delta ferrite content above 20%; (2) statically-cast parts with a molybdenum content meeting CF3 and CF8 limits and with a delta ferrite content above 20%; and (3) statically-cast parts with a molybdenum content exceeding CF3 and CF8 limits and with a delta ferrite content above 14%. [Reference 7, Section 4.8.2]

Since thermal aging of components is considered plausible for CASS parts with delta ferrite contents above the noted values, plants can compare the delta ferrite contents of components made of CASS with these values to determine if this ARDM is potentially significant. Plants can determine the delta ferrite content of their components utilizing established techniques. [Reference 18]

The effects could also be discovered by examination of components when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components that are loose, missing, cracked, or fractured would be readily observable by visual examination.

Loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 4 (Thermal Aging) - Aging Management Programs

Mitigation: Since there are no reasonable methods of mitigating thermal aging for the RVI, there are no programs credited with mitigation.

Discovery: The delta ferrite content will be determined for CCNPP's RVI components made from CASS, and the contents will be compared to the acceptable thresholds. Initial investigations revealed that formal calculations should show delta ferrite levels are below the established thresholds for these components. [Reference 3, Table 5-4, Delta Ferrite Calculation for CASS Components] The new calculations are expected to show that thermal aging is not plausible and would not affect the intended function of these components during the period of extended operation.

Alternatively, the effects could be discovered by an examination of components that are subject to thermal aging. Thermal aging could be discovered when the components are examined for loose, missing, cracked, or fractured components. Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

Group 4 (Thermal Aging) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of thermal aging on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Thermal aging is plausible for CASS components and could result in a loss of fracture toughness, which could lead to loose, missing, cracked, or fractured parts.
- A delta ferrite content calculation will be performed and is expected to show that the ARDM is not plausible and would not affect the intended functions of these components during the period of extended operation. If not, an examination will be performed.

Therefore, there is reasonable assurance that the effects of thermal aging will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 5 (Stress Relaxation) - Device Types, Materials, and Environment

Table 4.3-2 shows that stress relaxation is plausible for two device types in the RVI. This group of device types includes the CSTR (tie rods, nuts, and set screws only) and the CEASB (only the CEA shroud bolts, also referred to as CEA shroud socket-head cap screws in plant documentation). Note that the term CEA shroud bolts will be used below, although threaded structural fastener is more appropriate than bolt per the ASME Code definition where threaded structural fasteners join components other than at a pressure boundary.

The CSTR components are constructed of ASTM A-193, A-194, and A-479 steels. The CEA shroud bolts are made of AMS 5735 iron base superalloy A-286. [Reference 3, CSTR and CEASB, Attachment 3s]

The environment characteristics pertinent to stress relaxation are operating temperatures and neutron irradiation experienced during normal operations. Normal RCS operating temperatures are 548°F in the cold leg and 599.4°F in the hot leg. [Reference 2, Section 4.1.1, Table 4-1] For high energy neutron exposures, the closer a component is to the core, the larger the integrated exposure will become.

Group 5 (Stress Relaxation) - Aging Mechanism Effects

Stress relaxation is a potential ARDM for components which rely on preload to perform their function, and is the unloading of preloaded components caused by neutron irradiation at PWR operating temperatures.

This mechanism occurs under conditions of constant strain where part of the elastic strain is replaced with plastic strain. [Reference 7, Section 4.6.1] The influence of irradiation on stress relaxation behavior has been shown during laboratory experiments for stainless steel materials stressed at or above yield strength and exposed to significant irradiation (on the order of 1×10^{21} n/cm^2, >1 Mev). Therefore, when preloaded components are subject to PWR operating temperatures and significant radiation fields, stress relaxation could result in loss of preload, subsequent mechanical fatigue, and shortened life. [Reference 3, Attachment 7, Stress Relaxation] Fatigue could lead to parts that are loose, missing, cracked, or fractured. These effects are the precursors to the loss of the intended function for these components.

Calvert Cliffs has not discovered any stress-relaxation-related damage for the RVI. Also, there have not been RVI damage events at other PWRs that were identified as stress relaxation failures. [Reference 7, Section 3.3; Reference 5, Section 5.3]

Group 5 (Stress Relaxation) - Methods to Manage Aging

Mitigation: The effects of stress relaxation could be mitigated for the RVI by lowering the reactor operating temperatures or reducing the neutron fluence, neither of which is practical.

Discovery: Analyses can be performed to demonstrate that stress relaxation is not occurring or, if occurring, would have no effect on a component's intended function. The first type of analysis would show that the required combination of stress levels and radiation conditions are not present for RVI components that are preloaded during installation. For some components (e.g., certain sets of threaded structural fasteners), the installation in the RVI may be such that during normal operations the components experience forces (e.g., coolant flow and spring-loading forces) that reduce the initial tensile preload forces. When this occurs, the components would be subject to less tensile stress during operations and, thus, would not be subject to total loss of preload from stress relaxation.

Analyses could also be performed to show that, due to mechanical redundancy, a loss of preload from stress relaxation may be acceptable for certain subsets of a particular type of component during the period of extended operation. Some subassemblies of components in the RVI rely on multiple structural support systems. These are systems where multiple components are used to connect other components (e.g., when many bolts are used to connect one part to another). Analytical demonstrations can show that failure of a limited number of such support structures is acceptable (e.g., half of the bolts holding one part to another). Such limited failures do not necessarily imply failure of the connection or of the ability of the connected components to perform their intended function, since the multiplicity of support structures provides mechanical redundancy. This type of analysis can be used to demonstrate acceptable performance of multiple support structures when used in the RVI. [Reference 7, Section 6.2.1]

The effects of stress relaxation could also be discovered by examination of components when the reactor vessel is opened and the RVI components are examined. Visual examination techniques normally used for the RVI would not be appropriate to identify significant loss of preload. However, two alternate examination methods could be considered. One is a remote ultrasonic technique proposed to determine the change in length of a component due to stress relaxation. This technique would require appropriate baseline data on the as-built dimensions of a component for comparison to the ultrasonically measured current dimensions. A difference in length would be related to the loss of preload for the component. The second method would be a mechanical technique to measure the preload still on the component (e.g., with a torque wrench).

If the loss of preload would be sufficient to have allowed vibration leading to fatigue failures, remote visual examinations would identify loose, missing, cracked, worn, or fractured components. Timely corrective actions would be taken and would ensure that the RVI components remain capable of performing their intended functions under all CLB conditions. In such cases, the loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 5 (Stress Relaxation) - Aging Management Programs

Mitigation: Since there are no reasonable methods of mitigating stress relaxation for the RVI, there are no programs credited with mitigation.

Discovery: Because the CEA shroud bolts and CSTR (tie rods, nuts, and set screws) are preloaded during initial installation, stress relaxation could affect their structural support function as a loss of preload, which could lead to vibrations and accelerated mechanical fatigue, resulting in cracking. [Reference 3, CSTR and CEASB, Attachment 6s, Code E] For each of these types of components, an evaluation will be conducted to demonstrate that this ARDM will not occur for the stress levels and radiation conditions. [Reference 3, Table 5-1, Stress Relaxation] These analyses are described below along with an alternate examination method for each type of component.

The CEA shroud bolts were initially evaluated as part of a broader investigation of the potential for stress corrosion of A-286 threaded structural fastener applications in CE Nuclear Steam Supply Systems. [Reference 17] The investigation reviewed design, fabrication methods, operating stress levels, and time in service for A-286 threaded structural fasteners as compared to those in Babcock and Wilcox RVI which had experienced failures. The investigation indicated a potential for a small percentage of stress corrosion failures, based on the Babcock and Wilcox experience. As a result, the various CE applications of A-286 threaded structural fasteners were evaluated to determine the margin available for each. The available margin was considered to be the number of such fasteners required to meet ASME Code stress allowables to withstand normal operating plus upset condition loads. [Reference 15, Section 1.0]

Combustion Engineering's evaluation for stress corrosion for all CE plants will be further developed for stress relaxation of the CEA shroud bolts in the CCNPP RVI. That is, plant-specific analysis will be performed to refine the calculated stress levels on these bolts and demonstrate that they are not subject to substantial tensile stress during normal operations, and, thus, would not be subject to loss of preload from stress relaxation at PWR operating temperatures. [Reference 3, Table 5-1, Stress Relaxation Analysis or Sampling Inspection] Initial calculations revealed that the upward flow of RCS coolant and the upward force of the fuel assembly hold-down springs would more than offset the weight of the fuel alignment plate. Thus, the tensile stress levels should be far below those which would cause stress relaxation at PWR operating temperatures. [Reference 3, Table 5-4, Stress Relaxation of CEA Shroud Bolts]

If the analysis does not show the low stress levels expected, an examination of the CEA shroud bolts would be conducted as part of an Age-Related Degradation Inspection (ARDI) Program. [Reference 3, Attachment 8, CEASB, Stress Relaxation] The type of examination, the extent of the examination, and the acceptance criteria would be determined under the ARDI Program. [Reference 3, Table 5-1, Stress Relaxation Analysis or Sampling Inspection] Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

For the other device type in this group, the CSTR, an analysis will be conducted to address the tensile preloads and opposing forces acting on these components during operation. The analysis is expected to demonstrate that the fluence levels and/or stress levels are not sufficient for stress relaxation to occur to the extent where the intended function would be impaired during the period of extended operations. [Reference 3, Table 5-1, Stress Relaxation Analysis]

If the analysis does not show acceptably low stress levels, an examination of the tie rods would be conducted as part of an ARDI Program. An examination developed as part of the ARDI Program would be needed because the tie rods are located within the CS and, thus, are not accessible for visual examination. [Reference 3, Attachment 8, CSTR, Stress Relaxation] An ARDI examination could be developed to determine the actual preload using either ultrasonic or mechanical techniques. [Reference 3, Table 5-1, Stress Relaxation Analysis]

Ultrasonic examination techniques have been used at some utilities. [Reference 3, Attachment 8, CSTR, Stress Relaxation] Ultrasonic examination techniques would require development of baseline data on as-built dimensions for the tie-rods. The option of using mechanical techniques (e.g., torque wrench) for this examination is complicated by the need to first remove the locking straps to make accurate measurements of preload, and to then reinstall the straps. Both methods are technically feasible but complex. [Reference 3, Table 5-4, Stress Relaxation Analysis of Core Shroud Tie Rods and Bolts] The examination would verify that the unacceptable effects of this aging mechanism have not occurred for these bolts, or timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions.

Group 5 (Stress Relaxation) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of stress relaxation on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- Stress relaxation is plausible for RVI components and could lead to vibrations and accelerated mechanical fatigue, resulting in cracking.
- A stress relaxation analysis is expected to show that the ARDM would not affect the intended functions of these components during the period of extended operation.
- Alternatively, NDE techniques may be developed and examinations performed under an ARDI Program, and appropriate corrective action would be taken if significant damage from stress relaxation is discovered.

Therefore, there is reasonable assurance that the effects of stress relaxation will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 6 (Stress Corrosion Cracking) - Device Types, Materials, and Environment

Table 4.3-2 shows that SCC is a plausible ARDM for one device type, the CEASB (only for the CEA shroud bolts, also referred to as CEA shroud socket-head cap screws in plant documentation).

The CEA shroud bolts are constructed of AMS 5735 iron base superalloy A-286. [Reference 3, CEASB, Attachment 3]

The environment pertinent to SCC is the chemistry of the coolant. Although there is a strict chemistry control program in effect for the RCS, the A-286 material that these bolts are made from makes them susceptible to SCC while in the coolant.

Group 6 (Stress Corrosion Cracking) - Aging Mechanism Effects

Stress Corrosion Cracking/IGSCC/Intergranular Attack are potential ARDMs for RVI components fabricated from AMS 5735 iron base superalloy A-286. [Reference 3, Attachment 7, SCC]

Initiation and propagation of SCC require three factors to be present: (1) susceptible material, (2) a corrosive environment, and (3) the presence of tensile stresses. The corrosiveness of the environment depends on the oxygen and halogen concentrations in the RCS and the magnitude of the tensile stresses must exceed a threshold value before SCC can occur. A generally accepted value for threshold stress is the yield stress of the material of the component. [Reference 3, Attachment 7, SCC]

Intergranular SCC is SCC where the grain boundaries of a susceptible material are cracked due to the aggressive environment and sufficient stress levels. Intergranular attack is similar to IGSCC except that stress is not required for intergranular attack. [Reference 3, Attachment 7, SCC]

Stress corrosion cracking is considered to be plausible for RVI components which are fabricated of a susceptible material (e.g., A-286) and are subject to substantial stresses during plant operation (e.g., bolting). The effects of SCC are the initiation and growth of surface cracks in the metal. [Reference 3, CEASB, Attachment 6, Code A] This effect is the precursor to the loss of the intended function for these components.

Stress corrosion cracking has occurred at Babcock and Wilcox, Westinghouse, and Kraftwerk Union designed plants. [Reference 5, Section 5.2.2] There have been no indications of SCC failures of CEA shroud bolts on the RVI at CCNPP or any CE plants. [Reference 15, Section 2.0]

Group 6 (Stress Corrosion Cracking) - Methods to Manage Aging

<u>Mitigation</u>: The effects of SCC could not be mitigated further for the RVI beyond the strict chemistry control already in use for the RCS. See the discussion of the RCS primary chemistry control program in Section 4.1 of the BGE LRA.

<u>Discovery</u>: Analyses can be performed to demonstrate that the stress levels needed for SCC are not present or, if SCC is occurring, analyses could show it would have no effect on a component's intended function.

The first type of analysis would show that for some components, their installation in the RVI may be such that during normal operations the components experience forces (e.g., coolant flow and spring-loading forces) that reduce the initial tensile preload forces. When this occurs, the components would be subject to less tensile stress during operations and, thus, would be less susceptible to SCC.

Analyses could also be performed to show that, due to mechanical redundancy, a failure of some fraction of a particular type of component may be acceptable during the period of extended operation. For some subassemblies of RVI components that rely on multiple structural support systems, analytical demonstrations can show that failure of a fraction of the support structures is acceptable (e.g., half of the bolts are sufficient to adequately connect one part to another). This type of mechanical redundancy analysis can be used to demonstrate acceptable performance of multiple support structures in the RVI when such limited failures still maintain the ability of the connected components to perform their intended function. [Reference 7, Section 6.2.1]

The effects of SCC could also be discovered by examination of components when the reactor vessel is opened and the RVI components are examined. Ultrasonic techniques could be developed to examine bolts for indications of crack initiation.

Group 6 (Stress Corrosion Cracking) - Aging Management Programs

Mitigation: Since there are no reasonable methods of mitigating SCC for the RVI, there are no programs credited with mitigation.

Discovery: A stress analysis will be performed specifically to evaluate the potential for SCC of the CEA shroud bolts. [Reference 3, Attachment 2, SCC Analysis or Sampling Inspection] As noted in the section on stress relaxation, the stress levels in CEA shroud bolts were previously investigated by CE for their plants and the levels were compared to those in A-286 bolting which had failed at Babcock and Wilcox plants. [Reference 15] The maximum stresses on the CEA shroud bolts were found to be "slightly below the critical stress" for SCC. [Reference 3, CEASB, Attachment 6, Code A]

Combustion Engineering's investigation for all CE plants will be further developed on a plant-specific basis to refine the calculated stress levels on the CEA shroud bolts at CCNPP. This will allow the plant-specific loads (due to flows, weights, reactions, etc.) to be used to demonstrate that these bolts are not subject to substantial tensile stress during normal operation. [Reference 3, Table 5-4, SCC Analysis of CEA Shroud Bolts]

Initial calculations have revealed that the upward flow of reactor coolant and the upward force of the fuel hold-down springs would more that offset the weight of the fuel alignment plate. Thus, the tensile stress levels should be far below those which have ever resulted in SCC of this material and one of the key factors causing SCC would not be present for these bolts. [Reference 3, Attachment 10, SCC or ARDI]

If the analysis does not show the low stress levels expected, an examination of several of the CEA shroud bolts will be performed in an ARDI Program to determine if SCC precursors are present. [Reference 3, Attachment 2, SCC Analysis or Sampling Inspection] The type of examination, the extent of the examination, and the acceptance criteria would be determined under the ARDI Program.

The examination would provide additional assurance that the effects of SCC would not prevent the performance of the intended function of the CEA shroud bolts during the period of extended operation, or ensure that timely corrective actions will be taken so that the RVI components remain capable of performing their intended functions under all CLB conditions. [Reference 3, Attachment 8, CEASB, Stress Corrosion Cracking]

Group 6 (Stress Corrosion Cracking) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of SCC on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- SCC is plausible for RVI components and could result in the initiation and growth of surface cracks in the metal.
- A stress analysis will be performed to determine if one of the key factors required for SCC is absent, and thereby show that this ARDM would not affect the intended functions of these components during the period of extended operation.
- Alternatively, an examination of CEA shroud bolts in an ARDI Program will show that no SCC precursors are present. Examinations will be performed and appropriate corrective action will be taken if significant damage from SCC is discovered.

Therefore, there is reasonable assurance that the effects of SCC will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Group 7 (High Cycle Fatigue) - Device Types, Materials, and Environment

Table 4.3-2 shows that high cycle fatigue is a plausible ARDM for one device type, the CEASB (CEA shroud tubes, supports, channels, etc.).

These components are constructed of various stainless and alloy steels (ASTM A-240, A-269, A-276, and A-451). [Reference 3, CEASB, Attachment 3]

The environment pertinent to high cycle fatigue is the flow characteristics during normal operations. The components in areas of high RCS crossflows would be most susceptible. [Reference 3, CEASB, Attachment 6, Code BA] Also pertinent were the more severe flow characteristics during the hot functional testing which induced higher flow loads on the RVI without the flow resistance of the fuel assemblies. [Reference 7, Section 4.10.2]

Group 7 (High Cycle Fatigue) - Aging Mechanism Effects

Fatigue is the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points, and which may culminate in cracks or complete fracture after a sufficient number of fluctuations. The fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure. A component subjected to sufficient cycling with significant strain rates may develop cracking. The cracks may then propagate under continuing cyclic strains. [Reference 14]

Calvert Cliffs has not discovered any high-cycle fatigue-related failures in the RVI. High cycle fatigue has occurred at CE and Westinghouse designed plants. [Reference 5, Section 5.3] At two CE plants, flow-induced vibrations of the thermal shields resulted in damage to the base metal and welds of the thermal shield support lugs attached to the core barrel. These were removed to eliminate the problem. Programs instituted at other CE plants were successful in preventing degradation of the type experienced. [Reference 7, Section 3.3.2] The CCNPP units do not have thermal shields. [Reference 6, Table 3-1]

Fatigue is considered plausible for RVI components subjected to repeated stress/strain cycles caused by fluctuating mechanical and thermal loads. [Reference 7, Section 4.10.1] Reactor internals components have a potential for high cycle fatigue due to flow-induced vibration. High cycle fatigue occurs when cyclic loads are such that significant plastic deformation does not occur in the highly stressed regions, but the loads are of such frequency that a fatigue crack initiates. High cycle fatigue is highly dependent on the presence of stress concentrations associated with corners, notches and surface imperfections. The very large numbers of cycles associated with high cycle fatigue are generally caused by flow-induced vibrations which occur during hot functional tests or early in plant life, if at all. [Reference 3, Attachment 7, High Cycle Fatigue]

Group 7 (High Cycle Fatigue) - Methods to Manage Aging

Mitigation: The potential effects of high cycle fatigue during operation were addressed during the hot functional tests of the RVI at CCNPP and other CE-supplied reactors. A design change was made at CCNPP where high cycle fatigue was a concern for RVI components, (i.e., the thermal shields were not installed). [Reference 19] Because high cycle fatigue was addressed in these tests and with an early design change, programs are not needed to mitigate high cycle fatigue during operations.

Discovery: The effects of high cycle fatigue can be discovered when the reactor vessel is opened and the RVI components are examined. Visual examination techniques would normally be used and would typically include remote visual examinations utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Components that are loose, missing, cracked, or fractured would be readily observable by visual examination.

Loose parts may also be detected by the Loose Parts Monitoring System which monitors the RCS for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more. [Reference 2, Section 4.4.1]

Group 7 (High Cycle Fatigue) - Aging Management Programs

Mitigation: There are no CCNPP programs credited for mitigation of high cycle fatigue for the RVI.

Discovery: American Society of Mechanical Engineers Code Section XI ISI is the existing program credited for aging management of the effects of high cycle fatigue for the components in the RVI. The purpose, scope, bases, operating experience, etc., for the ISI Program are described above in the subsection, Group 1 (Wear) - Aging Management Programs. Any component damage from high cycle fatigue can be detected by ASME Code Section XI ISI Program requirements for Nuclear Class I components. [Reference 3, CEASB, Attachment 6, Code BA]

The nature of high cycle fatigue is such that it normally occurs early in plant life, making it highly unlikely that components subject to this ARDM will fail during the license renewal period. The performance of hot functional tests followed by years of operations without high cycle fatigue failures indicates that the stresses in the RVI components are well below the endurance limits for the materials. Without modifications to the design of the RVI, high cycle fatigue is a minor concern for the existing components.

Visual examination of the accessible areas of these components during normal refueling operation will be adequate to manage this ARDM. [Reference 3, Attachment 8, CEASB, High Cycle Fatigue] Timely corrective actions will be taken and will ensure that the RVI components remain capable of performing their intended functions under all CLB conditions. As noted above in the subsection, Group 1 (Wear) - Aging Management Programs, the current ISI Program implementing procedures will be modified to specifically identify RVI components which rely on this program for aging management for license renewal. [Reference 3, Attachment 2, Section XI ISI]

Group 7 (High Cycle Fatigue) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions demonstrate management of the effects of high cycle fatigue on the RVI components:

- The RVI components provide structural support to the fuel assemblies, CEAs, and ICI, and their configuration must be maintained under CLB conditions.
- High cycle fatigue is plausible for RVI components and could result in the initiation of a fatigue crack in highly stressed regions due to high frequency loads.
- The CCNPP ISI Program provides for periodic examinations of accessible surfaces of RVI components.
- Visual examinations will be performed, and appropriate corrective action will be taken if a fatigue crack is discovered.

Therefore, there is reasonable assurance that the effects of high cycle fatigue will be managed in order to maintain the structural integrity of RVI components consistent with the CLB during the period of extended operation.

Conclusion

The programs discussed for the RVI are listed in Table 4.3-3. The existing program is, and the new analyses and program will be, administratively controlled by a formal review and approval process. As has been demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the components of the RVI will be maintained consistent with the CLB during the period of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation processes for license renewal are in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

Table 4.3-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE REACTOR VESSEL INTERNALS

	Program	Credited As
Modified	Inservice Inspection of ASME Code Section XI Components, existing program implementing procedures for MN-3-110	Detection and management of the effects of wear (Group 1), neutron embrittlement (Group 2), and high cycle fatigue (Group 7) to show these ARDMs would not affect the intended function of components during the period of extended operation.
New	Low-Cycle Fatigue Analysis of Components Subject to Gamma Heating	Discovery of the effects of low cycle fatigue (Group 3) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or if fatigue usage is bounded by monitored components. The analysis may show specific components need to have fatigue usage tracked, or that an examination is needed.
New	Delta Ferrite Calculation for CASS Components	Discovery of the effects of thermal aging (Group 4) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or that an examination is needed.
New	Stress Relaxation Analysis	Discovery of the effects of stress relaxation (Group 5) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or that NDE techniques need to be developed and performed.
New	SCC Analysis of CEA Shroud Bolts	Discovery of the effects of SCC (Group 6) by showing whether this ARDM would affect the intended function of the components during the period of extended operation, or that an examination is needed.

	Program	Credited As
New	ARDI Program	Detection and management of the effects of ARDMs for which analysis is not able to demonstrate that an ARDM would not affect the intended function of the components during the period of extended operation (Groups 5 and 6).

REFERENCES:

1. System and Structure ITLR Screening Results, Life Cycle Management Renewal Program, BG&E, Revision 4, April 4, 1995
2. Calvert Cliffs Nuclear Power Plant Updated Final Safety Analysis Report, Revision 19, dated April 1, 1996
3. Reactor Vessel Internals Aging Management Review Report, Revision 2, February 27, 1997
4. Letter from Mr. J. M. Burger (ABB Combustion Engineering Nuclear Operations) to Mr. B. M. Tilden, (BGE) Response to Questions 1-4, RV Internals Aging Evaluation, NOME-95-B1-1085, December 1, 1995
5. NUREG/CR-6048 ORNL-TM-12371, "Pressurized-Water Reactor Internals Aging Degradation Study, Phase I, Oak Ridge National Laboratory, 1993
6. Reactor Internals Service Life Evaluation for Baltimore Gas and Electric Calvert Cliffs Units 1 & 2, Combustion Engineering, September 1988
7. EPRI-TR-103838, "PWR Reactor Pressure Vessel Internals License Renewal Industry Report; Revision 1," 1992
8. In-service Inspection Program Plan for the Second Inspection Interval for Calvert Cliffs Nuclear Power Plant Units 1 and 2, Southwest Research Institute, Project 17-1168, November 1987, Revision 0, Change 6, November 20, 1996
9. CCNPP Procedure MN-3, Pressure Boundary Codes and Special Processes Program, Revision 1, May 17, 1995
10. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for In-Service Inspection of Nuclear Power Plant Components," 1983 edition with Addenda through Summer 1983
11. CCNPP Procedure MN-3-110, In-service Inspection of ASME Section XI Components, Revision 2, July 2, 1996
12. 1989 Inservice Inspection Examination of Selected Class 1, Class 2, and Class 3 Components and Systems at Calvert Cliffs Nuclear Power Plant Unit 2, Southwest Research Institute, Project 2743, Appendix H, July 1991
13. Inservice Inspection Examination of Selected Class 1, Class 2, and Class 3 Components at Calvert Cliffs Nuclear Power Plant Unit 2, Southwest Research Institute, Project 5421, Appendix H, September 1993
14. "Metal Fatigue in Engineering," H. O. Fuchs and R. I. Stephens, John Wiley & Sons, Copyright 1980
15. Investigation and Evaluation of A286 Bolt Application in C-E's Nuclear Steam Supply System, C-E Owners Group, CEN-282, November 1984
16. Letter from Mr. J. P. Durr (NRC) to Mr. C. Stoiber *(sic)* (BGE), dated February 11, 1993, "Inspection Report Nos. 50-317/92-32 and 50-318/92-32"
17. CCNPP Procedure EN-1-300, Implementation of Fatigue Monitoring, Revision 0, February 28, 1996
18. NUREG/CR-6177, "Assessment of Thermal Embrittlement of Cast Stainless Steels," May 1994
19. CCNPP BGE Drawing 12021-0009, Core Support Barrel Details, Note 12

5.1 Auxiliary Feedwater System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Auxiliary Feedwater (AFW) System. The AFW System was evaluated in accordance with the Calvert Cliff Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.1.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.1.1.1 presents the results of the system level scoping, 5.1.1.2 the results of the component level scoping, and 5.1.1.3 the results of scoping to determine components subject to an AMR.

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently assigned cognizant CCNPP personnel.

5.1.1.1 System Level Scoping

This section begins with a description of the system that includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

<u>System Description/Conceptual Boundaries</u>

The AFW System is designed to provide emergency water from No. 12 Condensate Storage Tank (CST) to the steam generators for the removal of sensible and decay heat, and to cool the primary system to 300°F if the main condensate pumps or the main feed pumps are inoperative. Number 12 CST serves both Units 1 and 2. Three AFW pumps are installed per unit, consisting of one motor-driven and two non-condensing steam turbine-driven pumps. The steam turbine-driven AFW train may also be used for normal system cooldown to 300°F. The motor-driven portion of the system is designated for emergency use only (i.e., not for use during normal plant startup or shutdown - except testing is allowed). For a shutdown, only one pump is required to be operating, the others are in standby. Upon automatic initiation of AFW, one motor-driven and one turbine-driven pump automatically start. [Reference 1, Sections 10.3.1 and 10.3.2]

These pumps take suction from No. 12 CST, which provides 300,000 gallons of water for decay heat removal and cooldown of both units. Other major components of the AFW System include blocking valves, flow control valves, check valves, turbine steam isolation and governor valves, flow elements, and associated piping, instrumentation, and controls. [Reference 1, Section 10.3.2; Reference 2, Section 1.1.2; References 3 and 4]

The AFW System also includes the cables, conduit, and logic devices for the Auxiliary Feedwater Actuation System (AFAS). The AFAS has been installed to comply with regulatory directives resulting from the Three Mile Island Unit 2 accident in 1979, that required automatic starting capability and the addition of the motor-driven AFW pump. The AFAS starts the AFW pumps upon detection of very low level in either steam generator and it blocks AFW to a ruptured steam generator. [Reference 2, Section 1.1.2]

The motor-driven AFW pump has been provided with a fire hose connection on its suction as an alternate water source. Likewise, on loss of electric power (Appendix R scenario), a siamese fire hose connection may be installed at the automatic recirculation valve on the discharge side of the pump. [Reference 1, Section 10.3.2]

The majority of the original design of the AFW System was accomplished using the seismic design criteria typical for other CCNPP Class I systems. The non-seismic portion of the AFW System was examined in response to the Nuclear Regulatory Commission (NRC) Generic Letter 81-14, and it was determined that the safe shutdown earthquake would not have a significant effect on system function. [Reference 1, Section 10.3.1] Auxiliary feedwater piping for the steam-driven train is designed per American Nuclear Standards Institute [ANSI] B 31.1, and for the motor-driven train is designed per American Society of Mechanical Engineers [ASME] Section III, Class III Boiler and Pressure Vessel Code. [Reference 1, Table 10-1]

The AFW System has not had significant aging-related problems over its 20-year history. In 1991, evidence of corrosion was discovered in Unit 2 AFW pumps; however, this occurred following the extended plant outage, which began in 1989. [Reference 5] Once in 1993, and two times in 1994, CCNPP experienced failures of the governor valve stem on an AFW turbine. These failures were common to Terry Turbines at several plants. They were a result of the valve stem material being susceptible to corrosion. Terry Turbine governor valve stem failure received industry and regulatory attention in 1994 and 1995. As a result, the governor valve stems on all four Terry Turbine units at CCNPP have been replaced with new stems made from Inconel 718 Alloy, a corrosion-resistant material.

Calvert Cliffs has established a schedule to overhaul AFW pump turbines every 10 years. All four AFW pump turbines were overhauled the first time in 1988. Turbine No. 11 was overhauled the second time in 1996, and the No. 21 in 1997. The No. 12 and 22 Turbines are currently scheduled for the 1998 and 1998 outages, respectively. The inspections of AFW pump turbines during overhauls have revealed no defects such as cracks or corrosion. The AFW pump turbines are in good condition. The AFW turbine-driven pumps are overhauled every four years.

Figure 5.1-1 is a simplified diagram of the AFW System. This figure shows the AFW System that is addressed in this section and the primary process flow systems' interfaces. [References 3 and 4]

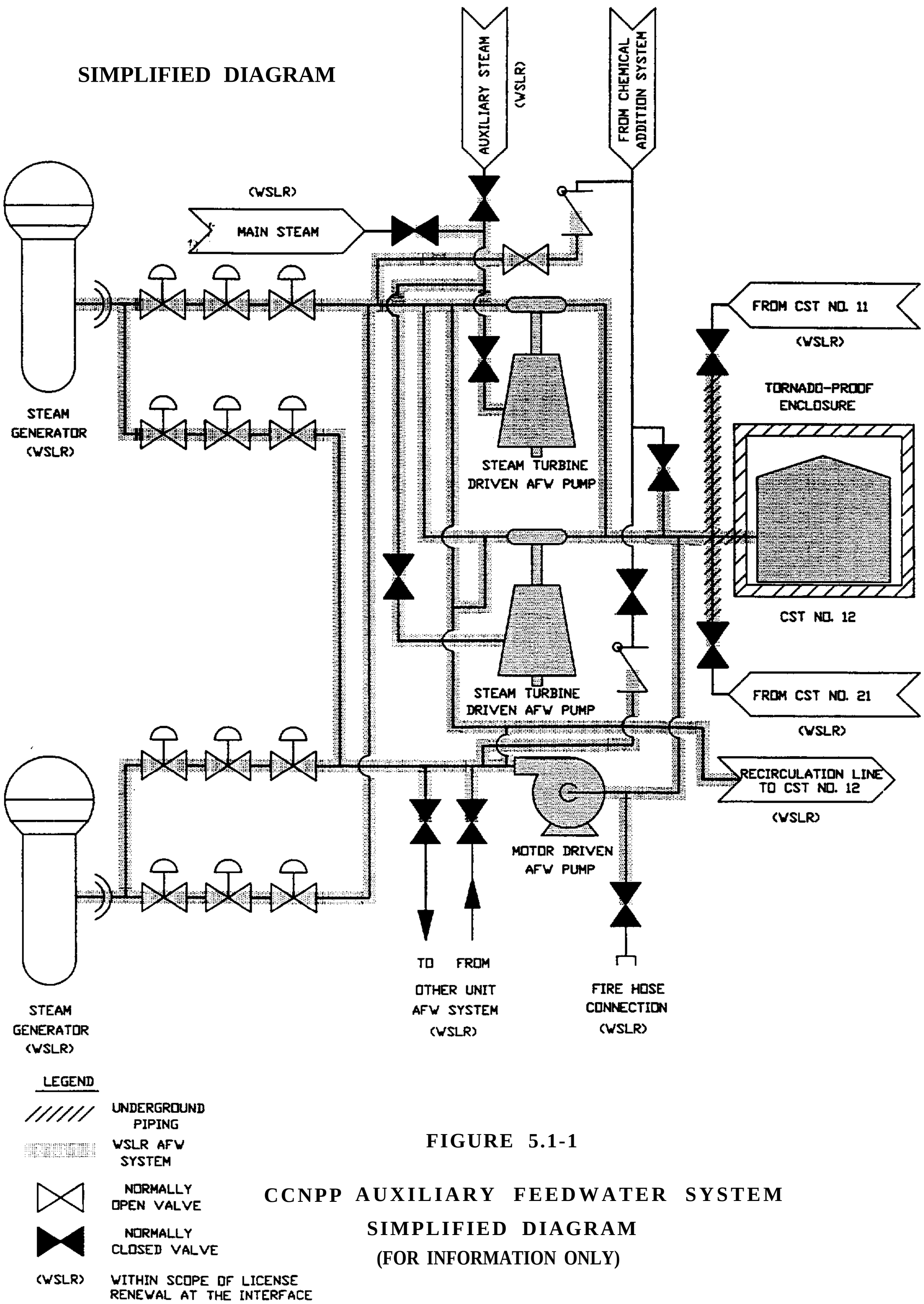


FIGURE 5.1-1

CCNPP AUXILIARY FEEDWATER SYSTEM
SIMPLIFIED DIAGRAM
(FOR INFORMATION ONLY)

System Interfaces:

The AFW System has interfaces with nine plant systems. The AFW scope relating to these interfacing systems is as follows:

- Demineralized Water and Condensate Storage System - The No. 12 CST and all connected SR pipes and instrumentation are included in the AFW scope. The No. 11 and 21 CSTs are non-safety-related (NSR). The AFW scope includes the SR isolation valves and the downstream pipes in the suction lines from these tanks. The valves provide an AFW pressure boundary function.
- Main Steam System - The turbine throttle valves through the governor valves to the turbine inlets.
- Chemical Addition System - The chemical injection pipes from the AFW headers out to and including the outboard SR isolation valves. The valves provide an AFW pressure boundary function.
- Engineered Safety Features Actuation System - The Engineered Safety Features Actuation System provides independent actuation for the AFAS. The steam generator instruments that generate the necessary signals are addressed in the Feedwater System AMR. Therefore, the interface involves cables/conduits associated with transmitting the AFAS signals to the AFW System, logic components, and controls associated with the pumps and valves.
- Auxiliary Steam System - The Auxiliary Steam System connects to the main steam piping upstream of the throttle/stop valves. Therefore, there are no auxiliary steam components in the scope of AFW. The system interface involves only the possible use of auxiliary steam to operate the turbine-driven pumps.
- Fire Protection System - The AFW motor-driven pumps may be supplied with a backup source of water by connecting a fire hose to the suction piping of the pump. The AFW scope includes the branch piping up to the SR isolation valves (which are adjacent to the NSR hose connection fittings). The valves provide an AFW pressure boundary function.
- Compressed Air System - All of the remote operated valves in the system use air actuators. These are controlled with compressed air normally provided from the NSR portion of the Compressed Air System. Air can be provided from the two SR air accumulators for a two-hour time period following a loss of function of, or loss of power to, the NSR Compressed Air System.
- Saltwater Air Compressor System - The SR Saltwater Air Compressor System ties into the Compressed Air System as an emergency backup source of compressed air. Therefore, there are no saltwater air compressor components in the scope of AFW. The system interface involves only the possible introduction of compressed air from the SR Saltwater Air Compressor System into components utilizing compressed air.
- Reactor Coolant System (steam generators) - Piping up to the steam generator AFW nozzles. [Reference 2, Section 1.1.2]

System Scoping Results

The AFW System is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the AFW System were determined based on the requirements of §54.4(a)(1) and (2) in accordance with the CCNPP IPA Methodology Section 4.1.1. [Reference 2, Section 1.1.3; Reference 6, Table 1]

- Provide AFW to the steam generators for decay heat removal;
- Maintain the pressure boundary of the system;
- Isolate the AFW to the steam generator;
- Maintain electrical continuity and /or provide protection of the electrical system;
- Provide circuit protection for the steam generator pressure signal being provided from the feedwater system to Engineered Safety Features Actuation System and Reactor Protective System;
- Provide seismic integrity and/or protection of SR components; and
- Provide flow restriction to assure adequate recirculation flow for pump cooling, and to limit recirculation flow such that adequate AFW flow is provided to the steam generators.

The following intended functions of the AFW System were determined based on the requirements of §54.4(a)(3): [Reference 2, Section 1.1.3; Reference 6, Table 1]

- For environmental qualification (§50.49) - Maintain functionality of electrical components as addressed by the environmental qualification program, and provide information used to assess the plant and environs condition during and following an accident
- For anticipated transients without scram (§50.62) - Provide AFAS Start Signal (diverse from Reactor Protective System) on low steam generator water level conditions indicative of an anticipated transient without scram.
- For station black out (§50.63) - Provide AFW to steam generators for decay heat removal and provide condensate inventory.
- For fire protection (§50.48) - Monitor essential AFW parameters to ensure safe shutdown in the event of a postulated fire. Parameters monitored include AFW pump discharge pressure & No. 12 CST level. Provide alternate control of the AFW System via local hand valves, flow transmitters, and current/pneumatic components at the auxiliary shutdown panel to ensure safe shutdown in the event of a postulated fire.

5.1.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the AFW System that is within the scope of license renewal includes all components (electrical, mechanical, and instrument) and their supports from the CST to the steam generators. These components include No. 12 CST, two turbine-driven and one motor-driven AFW pumps, steam generator blocking valves, steam generator flow control valves, check valves, piping, instrumentation, and AFAS. [Reference 2, Section 1.1.2]

The following 47 device types of the AFW System were designated as within the scope of license renewal because they have at least 1 intended function: [Reference 2, Table 2-1]

AFW System Piping -EB	AFW System Piping -EBB
AFW System Piping -EBC	AFW System Piping -EC
AFW System Piping -HB	AFW System Piping -HBC
AFW System Piping -HC	2/4 Logic Component
Check Valve	Coil
Control Valve and Control Valve Operator	Voltage/Current Device
Flow Element	Flow Indicator
Flow Indicator Controller	Flow Orifice
Flow Transmitter	Fuse
Flow Component (Relay)	Governor Valve
Hand Controller	Handswitch
Hand Valve	Current/ Voltage Device
Current/Current Device	Current/Pneumatic Device
Ammeter	Power Lamp Indicator
Level Indicator	Level Indicator Alarm
Level Transmitter	4KV Motor
125/250 VDC Motor	Pressure Control Valve
Pressure Indicator	Panel
Pressure Switch	Pressure Transmitter
Pump	Relay
Solenoid Valve	Tank
Turbine	Vacuum Breaker Valve
Power Supply	Position Indicating Lamp
Position Switch	

Some components in the AFW System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 2, Section 3.2]

- Structural supports for piping, cables, and components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA.
- Electrical control and power cabling are evaluated for the effects of aging in the Cables Evaluation in Section 6.1 of the BGE LRA.
- Instrument tubing and piping and the associated supports, instrument valves, and fittings (generally everything from the outlet of the final root valve up to and including the instrument), and the pressure boundaries of the instruments themselves, are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

5.1.1.3 Components Subject To Aging Management Review

This section describes the components within the AFW System that are subject to AMR. It begins with a listing of passive intended functions, and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with the CCNPP IPA Methodology Section 5.1, the following AFW System functions were determined to be passive. [Reference 2, Table 3-1]

- Maintain the pressure boundary of the system;
- Maintain electrical continuity and/or provide protection of the electrical system;
- Provide seismic integrity and/or protection of SR components; and
- Provide flow restriction to assure adequate recirculation flow for pump cooling, and to limit recirculation flow such that adequate AFW flow is provided to the steam generators.

Device Types Subject to Aging Management Review

Of the 47 device types within the scope of license renewal:

- The following 21 device types do not have a passive intended function; two-out-of-four (2/4) logic component, coil, voltage/current component, flow indicator, flow indicator controller, fuse, flow component, hand controller, hand switch, current/voltage component, current/current component, ammeter, power lamp indicator, level indicator alarm, 4KV motor, 125/250 VDC motor, relay, vacuum breaker valve, power supply, position indicating lamp, position switch. [Reference 2, Table 3-2]
- The flow transmitter device type consists of 16 flow transmitters that are within the scope of license renewal. Four of the transmitters are subject to a replacement program and twelve transmitters are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of this application. [Reference 2, Table 3-2]
- The following five device types are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of this application; Level Indicator, Level Transmitter, Pressure Indicator, Pressure Switch, and Pressure Transmitter. [Reference 2, Table 3-2]
- One device type, Panel, is evaluated for the effects of aging in the Electrical Panels Commodity Evaluation in Section 6.2 of the BGE LRA.

The remaining 19 device types that require AMR are listed in Table 5.1-1. These are the subject of the rest of this section. Unless otherwise annotated, all components of each listed device type are covered. [Reference 2, Table 3-2]

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

TABLE 5.1-1

DEVICE TYPES REQUIRING AMR FOR AFW SYSTEM

Device type	Device Type Description
EB	AFW Piping- EB
EBB	AFW Piping- EBB
EBC	AFW Piping- EBC
EC	AFW Piping- EC
HB	AFW Piping- HB (2)
HBC	AFW Piping- HBC
HC	AFW Piping- HC
CKV	Check Valve (1)
CV	Control Valve and CV Operator
FE	Flow Elements
FO	Flow Orifice
GOV	Governor Valve
HV	Hand Valve (1) (2)
I/P	Current/Pneumatic Device (3)
PCV	Pressure Control Valve
PUMP	Pump
SV	Solenoid Valve
TK	Tank
TURB	Turbine

Notes:

(1) Instrument line manual drain, equalization, and isolation valves in the AFW System that are subject to AMR are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of this application. Instrument line manual root valves are evaluated in this report. [Reference 7, Attachment 3]

(2) Hand valves and piping, which are relied upon for safe shutdown in the event of a fire and are classified as NSR, are evaluated for the effects of aging in the Fire Protection Evaluation in Section 5.10 of the BGE LRA. All SR valves and piping are evaluated in this report. [Reference 8]

(3) A total of 24 current/pneumatic devices are within the scope of license renewal. Only eight of these devices are subject to AMR and are included in this report. The other 16 are not subject to AMR because they are either included in a replacement program or they have only active intended functions.

5.1. Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the AFW System device types is given in Table 5.1-2. [Reference 2, Table 4-2] The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate device type column. For AMR, some device types have a number of groups associated with them because of the diversity of material used in their fabrication or differences in the environments to which they are subjected. A check mark indicates that the ARDM applies to at least one group for the device type listed. For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. Table 5.1-2 also identifies the group to which each ARDM/device type combination belongs. The following groups have been selected for the AFW System.

Group 1 - cavitation erosion of AFW piping- EB;

Group 2 - internal surface corrosion in a water environment;

Group 3 - external surface corrosion in an atmospheric environment;

Group 4 - external surface corrosion of buried pipe;

Group 5 - internal surface corrosion in a steam environment;

Group 6 - external surface corrosion of the turbine-driven pump;

Group 7 - wear and elastomer degradation of solenoid-operated valves;

Group 8 - general corrosion of control valve operators; and

Group 9 - elastomer degradation of No. 12 CST perimeter seal.

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods of managing aging, aging management program(s), and aging management demonstration.

Group 1 (cavitation erosion of AFW piping- EB) - Materials and Environment

The pipe and fitting material for the AFW System Class EB piping is carbon steel, American Society for Testing and Materials [ASTM] A106 GR B. The bolting material is alloy steel. The material for the nuts is carbon steel. Cavitation erosion is only considered to be plausible for the internal piping surfaces. The bolts and nuts are not exposed to the process fluid. [Reference 2, Attachments 4 and 6]

TABLE 5.1-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE AFW SYSTEM

	Device Types for Which ARDM is Plausible								
POTENTIAL ARDMs	**TK**	**FE**	**I/P**	**GOV**	**EB**	**EC**	**HB**	**HC**	**FO**
Cavitation Erosion									
Corrosion Fatigue									
Crevice Corrosion	✓(3)			✓(5)	✓(2)		✓(2, 3, 4)		
Dynamic Loading									
Electrical Stressors									
Erosion Corrosion				✓(5)					
Fatigue									
Fouling									
Galvanic Corrosion							✓(4)		
General Corrosion	✓(3)			✓(5)	✓(2)		✓(2, 3, 4)		
Hydrogen Damage									
Intergranular Attack									
Microbiologically-Induced Corrosion (MIC)							✓(4)		
Pitting	✓(3)			✓(5)	✓(2)		✓(2, 3, 4)		
Radiation Damage									
Elastomer Degradation	✓(9)								
Selective Leaching									
Stress Corrosion Cracking									
Thermal Damage									
Thermal Embrittlement									
Wear									

✓ - Indicates plausible ARDM determination for at least one group for the device type listed.
(#) - Indicates the group(s) in which this ARDM/device type combination is evaluated

Note: Not every group within the device types listed here may be susceptible to a given ARDM. This is because groups within a device type are not always fabricated from the same materials or subject to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

Note: Cavitation erosion is plausible for only portions of the EB piping. Those portions are immediately downstream of flow orifices 1/2 FO 4506, 4507, and 4540 due to the large pressure drops of these locations.

TABLE 5.1-2 (continued)

POTENTIAL AND PLAUSIBLE ARDMs FOR THE AFW SYSTEM

	Device Types for Which ARDM is Plausible							
POTENTIAL ARDMs	**PUMP**	**PCV**	**TURB**	**CKV**	**CV**	**HV**	**SV**	**CV (OP)**
Cavitation Erosion								
Corrosion Fatigue								
Crevice Corrosion	✓(2, 6)		✓(5)	✓(2, 3)	✓(2, 5)	✓(2, 3)		
Dynamic Loading								
Electrical Stressors								
Erosion Corrosion			✓(5)		✓(5)			
Fatigue								
Fouling								
Galvanic Corrosion								
General Corrosion	✓(2)		✓(5)	✓(2, 3)	✓(2, 5)	✓(2, 3)		✓(8)
Hydrogen Damage								
Intergranular Attack								
MIC								
Pitting	✓(2, 6)		✓(5)	✓(2, 3)	✓(2, 5)	✓(2, 3)		
Radiation Damage								
Elastomer Degradation							✓(7)	
Selective Leaching								
Stress Corrosion Cracking								
Thermal Damage								
Thermal Embrittlement								
Wear							✓(7)	

✓ - Indicates plausible ARDM determination for at least one group for the device type listed.
(#) - Indicates the group(s) in which this ARDM/device type combination is evaluated.

Note: Not every group within the device types listed here may be susceptible to a given ARDM. This is because groups within a device type are not always fabricated from the same materials or subject to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

The internal surfaces of the piping are exposed to chemistry controlled water below 200°F. For most of the AFW System, fluid flow (when in use), pressure, temperature, and in-line component pressure drops do not create conditions required for cavitation. The flow is relatively steady and the pressure is much greater than vapor pressure at system operating and standby temperatures. However, large pressure drops at flow orifices 1/2FO4506, 4507 and 4540 may result in cavitation in the Class EB piping at these locations. [Reference 2, Attachments 3, 4, and 6]

Group 1 (cavitation erosion of AFW Class EB piping) - Aging Mechanism Effects:

As stated above, for most of the AFW System, the flow is relatively steady and the pressure is much greater than vapor pressure at system operating and standby temperatures. However, given the high pressure drop and low recovered downstream pressure at flow orifices 1/2FO4506, 4507, and 4540, cavitation erosion is considered plausible at these locations. The resulting material loss would be localized in nature and within several pipe diameters downstream of the orifice plates. The degradation from cavitation erosion typically erodes component walls quickly. Cavitation erosion causes loss of material and reduces the cross-sectional area. [Reference 2, Attachment 6] If left unmanaged, cavitation erosion could eventually result in the loss of pressure-retaining capability under current licensing basis (CLB) design loading conditions.

Group 1 (cavitation erosion of AFW Class EB piping) - Methods to Manage Aging:

Mitigation: The occurrence of cavitation erosion is expected to be limited and is unlikely to affect the intended function of the AFW System Group 1 components due to the limited amount of time the system is in operation.. Therefore, no specific mitigation measures are deemed necessary.

Discovery: An inspection of potentially affected piping components will provide assurance that significant cavitation erosion is not occurring, or will result in initiation of corrective action if significant cavitation erosion is occurring. [Reference 2, Attachment 8] Representative samples of susceptible locations can be used to assess the need for additional inspections at less susceptible locations. Based on piping/component geometry and fluid flow conditions, areas most likely to experience cavitation erosion can be determined and evaluated.

Group 1 (cavitation erosion of AFW Class EB piping) - Aging Management Program(s):

Mitigation: There are no specific programs credited for mitigation of cavitation erosion of AFW Class EB piping.

Discovery: Cavitation erosion can be readily detected through non-destructive examination techniques. However, due to the limited use of this system, the occurrence of this ARDM is expected to be limited and not likely to affect the intended function. As such, an inspection program can provide the additional assurance needed to conclude that the effects of plausible aging are not threatening the ability of the subject piping to perform its intended function for the period of extended operation. [Reference 2, Attachment 8]

The internal surfaces of AFW piping Class EB, down stream of flow orifices 1/2 FO 4506, 4507, and 4540, will be included in a new CCNPP Age-Related Degradation Inspection (ARDI) Program to accomplish the needed inspections for cavitation erosion. This program is considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0.

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;

- Identification of inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of unacceptable examination findings, including consideration of all design loadings required by the CLB, and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

The corrective actions will be taken in accordance with the CCNPP Corrective Action Program and will ensure that the Class EB piping will remain capable of performing the system pressure boundary integrity function under all CLB conditions.

Group 1 (cavitation erosion of AFW Class EB piping) - Aging Management Demonstration:

Based on the information presented above, the following conclusions can be reached with respect to cavitation erosion of the internal surfaces of the Class EB piping of the AFW System.

- The Class EB piping contributes to the system pressure boundary function.
- Given the high pressure drop across the flow orifices and low recovered downstream pressure, cavitation erosion is considered a plausible ARDM for the Class EB piping. The resulting material loss is localized in nature and would be of most concern within several pipe diameters downstream of the orifice plates.
- Due to the limited use of the system, it is not likely this ARDM will affect the intended function of the piping. However, if left unmanaged, this ARDM could eventually result in the loss of pressure-retaining capability under CLB design loading conditions.
- To provide the additional assurance needed to conclude that the effects of this ARDM are not threatening the ability of the piping to perform its intended function, the internal surfaces of AFW piping, down stream of flow orifices 1/2 FO 4506, 4507, and 4540, will be included in the scope of an ARDI Program. Inspections will be performed and appropriate corrective action will be taken if significant degradation is discovered.

Therefore, there is a reasonable assurance that the effects of aging will be adequately managed for the AFW Class EB piping such that it will be capable of performing its intended function, consistent with the CLB, during the period of extended operation.

Group 2 (internal surface corrosion in a water environment) - Materials and Environment

Group 2 consists of components that have an internal environment of treated water and whose internal surfaces are subject to crevice corrosion, general corrosion, and/or pitting. The device types that have at least one component with Group 2 attributes include Class EB piping, Class HB piping, motor-driven AFW pumps, check valves, control valves, and hand valves. The subcomponents in these device types that are exposed to water are constructed of the following materials: [Reference 2, Attachments 4 and 6]

- Class EB piping - carbon steel pipe and fittings;
- Class HB piping - carbon steel pipe and fittings;
- motor-driven AFW pumps - carbon steel casing with carbon steel, alloy steel, and stainless steel (martensitic) internal subcomponents;
- check valves - carbon steel body/bonnet and bearing caps (Note: Check valve internals are not subject to AMR because the valves are not required to be in a closed position for maintaining the system pressure boundary. The only exception to this is the check valves that provide the pressure boundary between the AFW System and the Chemical Addition System. Those check valves have internals constructed of stainless steel.);
- control valves - carbon steel body/bonnet with stainless steel stem (Note: None of the valves are required to be in the closed position for maintaining the system pressure boundary.); and
- hand valves - carbon steel body/bonnet with alloy steel, stellited carbon steel, and stainless steel internal subcomponents.

The environment for internal surfaces of most of the Group 2 components is AFW that is below 200°F. The source of water for the AFW System is one of the three CSTs (Nos. 11, 12, or 21), which contain water that is monitored and controlled through the Secondary Chemistry Program. The Secondary Chemistry Program the CSTs in order to maintain the fluid chloride and sulfate levels below predetermined limits. The portion of the Class EB piping from the check valve to the steam generator has an internal environment of chemistry controlled water, i.e., feedwater, below 532°F. The check valve that isolates the AFW System from the Chemical Addition System is exposed to demineralized water below 200°F that contains chemicals such as hydrazine, ammonia, and amines. [Reference 2, Attachment 1; Reference 9]

Group 2 (internal surface corrosion in a water environment) - Aging Mechanism Effects:

Crevice corrosion, general corrosion, and/or pitting are plausible for Group 2 components because some of the materials used in their construction are susceptible to these corrosion mechanisms when exposed to a wet environment. The aggressiveness of these corrosion mechanisms is particularly dependent on water chemistry conditions and oxygen levels in the water and on the materials of construction. [Reference 2, Attachment 6]

General corrosion is thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. General corrosion requires an aggressive environment and materials susceptible to that environment. Wastage is not a concern for austenitic stainless steel alloys. The consequence of the damage is loss of load-carrying cross-sectional area. [Reference 2, Attachments 6 and 7]

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. 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. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as leading to stress corrosion cracking. [Reference 2, Attachments 6 and 7]

Pitting is another form of localized attack with greater corrosion rates at some locations than at others. Pitting can be very insidious and destructive, with sudden failures in high pressure applications (especially in tubes) occurring by perforation. This form of corrosion essentially produces holes of varying depth to diameter ratios in the steel. Pits are generally elongated in the direction of gravity. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. [Reference 2, Attachment 6s and 7s]

For Group 2 components, long-term exposure to the water environment may result in localized and/or general area material loss and, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. The areas where there are stagnant conditions, e.g., drain lines and crevices, are the locations most susceptible to these corrosion mechanisms. All three of these ARDMs are plausible for carbon steel and alloy steel subcomponents. Subcomponents constructed of stellited carbon steel or martensitic stainless steel are susceptible to crevice corrosion and pitting only. This is because these materials are resistant to general corrosion. [Reference 2, Attachment 6]

Crevice corrosion, general corrosion, and pitting are not plausible for subcomponents constructed of austenitic stainless steel due to the inherent corrosion resistance of the material and the non-aggressiveness of the environment. System chemistry control maintains the fluid non-corrosive by limiting the concentration of chlorides and sulfates. Additionally, system operating temperatures ($\leq$ 100°F) and standby temperatures ($\leq$ 140°F) are low, thus minimizing corrosive effects. Therefore, the effects of these ARDMs are minimal and have no effect on the intended function of the components. Based on these considerations, crevice corrosion, general corrosion, and pitting are not plausible for subcomponents constructed of austenitic stainless steel. [Reference 2, Attachment 6]

Group 2 (internal surface corrosion in a water environment) - Methods to Manage Aging:

<u>Mitigation:</u> The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of the Group 2 components and the piping material to an aggressive environment. Maintaining an internal environment of purified water with dissolved oxygen and other impurities maintained at low levels, results in limited corrosion reactions. In some cases, the initial formation of a passive oxide layer (magnetite) also protects the pipe interior surface by minimizing the exposure of bare metal to water. [Reference 2, Attachments 6 and 7]

<u>Discovery:</u> The occurrence of corrosion (crevice corrosion, general corrosion, and pitting) is expected to be limited and is unlikely to affect the intended function of the AFW System Group 2 components due to the control of fluid chemistry. An inspection of representative plant components will provide assurance that significant corrosion is not occurring, or will result in initiation of corrective action if significant corrosion

is occurring. [Reference 2, Attachment 8] Representative samples of susceptible locations can be used to assess the need for additional inspections at less susceptible locations. Based on piping/component geometry and fluid flow conditions, areas most likely to experience corrosion can be determined and evaluated.

Group 2 (internal surface corrosion in a water environment) - Aging Management Programs:

Mitigation:

CCNPP Secondary Chemistry Specifications and Surveillance Program

The CCNPP Secondary Chemistry Specifications and Surveillance Program has been established to control bulk fluid chemistry of several plant systems, including the CSTs, to reduce corrosion product generation, transport, and deposition on system components. [Reference 10, Section 6.1.A] The scope of the Secondary Chemistry Program includes: steam generators, CSTs, Feedwater System, Condensate System, Main Steam System, heater drain tanks, condensate demineralizer effluent, steam generator blowdown ion exchanger effluent, and condensate precoat filters. [Reference 9, Section 2.C] The program is based on References 11 through 16.

The Secondary Chemistry Program monitors fluid chemistry in the CSTs, including make-up water to the CSTs, in order to minimize the concentration of corrosive impurities (chlorides, sulfates, oxygen). Control of fluid chemistry minimizes the corrosiveness of the environment for AFW System components, thereby minimizing the rate and effects of corrosion. The rate of corrosion is also reduced in some cases by the initial buildup of a passive oxide layer (magnetite) that minimizes bare metal exposure to water. [Reference 2, Attachment 6s; Reference 9]

Secondary chemistry parameters (e.g., dissolved oxygen) are measured at procedurally-specified frequencies. The measured parameter values are compared against “target” values which represent a goal or predetermined warning limit. If a value is out of bounds, corrective actions are taken as prescribed by secondary chemistry procedure CP-217, "Specifications and Surveillance: Secondary Chemistry," thereby ensuring timely response to chemical excursions. [Reference 9, Sections 6.0.C and Attachment 9] The Secondary Chemistry Program has the target and action values based on chemistry guidelines provided by Electric Power Research Institute, Institute for Nuclear Power Operations (INPO), and the Nuclear Steam Supply System vendor. The corrective actions taken will help minimize the aggressiveness of the internal environment of AFW System Group 2 components so that they remain capable of performing their intended functions under all CLB conditions.

The Secondary Chemistry Program is subject to internal assessment activity both within the Chemistry Department and through the site performance assessment group. The program is recognized through these assessments as maintaining highly effective secondary chemistry controls and aggressively pursuing continuous improvements through monitoring industry initiatives and trends in the area of secondary systems corrosion control. The program is also subject to frequent external assessments by INPO, NRC, and others.

Operating experience relative to the Chemistry Program at CCNPP has been such that no site-specific problems or events related to these aging mechanisms are known to have occurred that required changes or adjustments to the program. It has been effective in its function of mitigating corrosion and corrosion-related failures and problems. The main focus of the program is steam generator chemistry. It has been demonstrated that as long as steam generator chemistry is carefully monitored and controlled, the other secondary systems are also successfully controlled. Calvert Cliffs has been proactive in making programmatic changes to the Secondary Chemistry Program over its history largely in response to developments within the industry, such as successful experimentation with a new alternate amine.

CCNPP Demineralized Water Chemistry Specifications and Surveillance Program

The CCNPP Demineralized Water Chemistry Specifications and Surveillance Program has been established to: minimize impurity ingress to plant systems; reduce corrosion product generation, transport, and deposition; reduce collective radiation exposure through chemistry; improve integrity and availability of plant systems; and extend component and plant life. [Reference 10, Section 6.1.A] The demineralized water chemistry program is applicable to the Demineralized Water and Well Water Systems for use in primary, auxiliary, and secondary plant systems. The program is based on References 17 through 21. [Reference 22, Section 2]

The demineralized water chemistry program controls fluid chemistry in order to minimize the concentration of corrosive impurities and dissolved oxygen. The demineralized water chemistry parameters (e.g., specific conductivity, dissolved oxygen, chloride, fluoride, sulfate) are measured at procedurally-specified frequencies. The measured parameter values are compared against “target” values, which represent a goal or predetermined warning limit. [Reference 22, Attachment 3] If a value is out of bounds, special and/or general corrective actions (such as, resampling, increased surveillance frequency, technical evaluation) are taken as prescribed by procedure [Reference 22, Section 6.0] This will help ensure that the aggressiveness of the internal environment for check valves that are located at the interface of AFW System and Chemical Addition System is minimized so that they remain capable of performing their intended functions under all CLB conditions.

The demineralized water chemistry program is subject to internal assessment activity, both within the Chemistry Department and through the site performance assessment group. The program is recognized through these assessments as maintaining highly effective secondary chemistry controls and aggressively pursuing continuous improvements through monitoring industry initiatives and trends in the area of secondary systems corrosion control. The program is also subject to frequent external assessments by INPO, NRC, and others.

The CP-202 program, "Specifications and Surveillance- Demineralized Water, Safety Related Battery Water, Well Water Systems, and Acceptance Criteria for On-line Monitors," since its inception, has essentially remained the same and has performed well. The changes in the limits of chemistry parameters are reflective of upgrades in the capability of measuring instruments and experience gained over the years.

Discovery:

CCNPP ARDI Program

For Group 2 components, crevice corrosion, general corrosion, and pitting can be readily detected through visual inspections. Due to the control of water chemistry, the occurrence of crevice corrosion, general corrosion, and pitting is expected to be limited and not likely to affect the intended function of the Group 2 components. An inspection program can provide the additional assurance needed to conclude that the effects of plausible aging are being effectively managed for the period of extended operation. [Reference 2, Attachment 8]

All Group 2 components will be included within a new plant program to accomplish the needed inspections for corrosion. This program is considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program.

Corrective actions will be taken in accordance with the CCNPP Corrective Action Program and will ensure that the components will remain capable of performing their pressure boundary integrity function under all CLB conditions.

Group 2 (internal surface corrosion in a water environment) - Aging Management Demonstration:

Based on the information presented above, the following conclusions can be reached with respect to general corrosion, crevice corrosion, and pitting of AFW System Group 2 components:

- The AFW System Group 2 components contribute to the system pressure boundary function and their integrity must be maintained under all CLB conditions.
- Crevice corrosion, general corrosion, and pitting are plausible ARDMs for this group of components and could result in material loss which, if left unmanaged, can lead to loss of pressure-retaining capability under CLB design loading conditions.
- The CCNPP Secondary Chemistry Specifications and Surveillance Program controls fluid chemistry in the CSTs, which minimizes the corrosiveness of the environment for the AFW System components.
- CCNPP Demineralized Water Chemistry Specifications and Surveillance Program controls the fluid chemistry for the supply of water to the Chemical Addition System, and hence to the AFW System, to minimize the corrosiveness of the environment for the AFW components that interface with that system.
- The occurrence of these ARDMs is expected to be limited and not likely to affect the intended function of the Group 2 components due to the control of fluid chemistry, low operating temperatures, and the limited operation.
- To provide the additional assurance needed to conclude that the effects of corrosion are being effectively managed, the components exposed to water will be included in the scope of an ARDI Program. Inspections will be performed and appropriate corrective action will be taken if significant corrosion is discovered.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting on Group 2 components will be adequately managed such that they will be capable of performing their pressure boundary integrity function, consistent with the CLB, during the period of extended operation.

Group 3 (external surface corrosion in an atmospheric environment) - Materials and Environment

Group 3 consists of components that are exposed to an atmospheric external environment and whose external surfaces are subject to crevice corrosion, general corrosion, and/or pitting. The device types that have at least one component with Group 3 attributes include Class HB piping, check valves, hand valves, and tanks. The subcomponents in these device types that are exposed to atmospheric conditions are constructed of the following materials: [Reference 2, Attachments 4 and 6]

- Class HB piping - carbon steel pipe with alloy steel studs and carbon steel nuts;
- check valves - carbon steel body with alloy steel studs and carbon steel nuts;
- hand valves - carbon steel body with carbon steel, alloy steel, or stainless steel stems, studs and nuts; and
- tanks - stainless steel tank with carbon steel anchor bolts/nuts.

The AFW System Group 3 components are exposed to two different external environments. In one environment there is piping, check valves, and hand valves located inside of a concrete valve pit, which is normally closed and thereby not readily accessible. The air inside the valve pit is normal outside atmosphere and, since it is not conditioned, may contain high humidity. [Reference 2, Attachment 6]

In the other environment there is piping, hand valves, and a tank located inside of the concrete No. 12 CST enclosure. The enclosure has openings to the outside, allowing for air changes generated by wind, but provides full protection from rain. The concrete structure thermal mass causes the internal temperatures to remain fairly constant. The resulting environmental conditions are non-wetted, varying humidity, and low, stable temperatures. However, extremes in humidity and temperature may result in surface moisture on the protected components. A tank perimeter seal (caulk) is provided between the elevated ring foundation and No. 12 CST to prevent moisture from being channeled under the tank. Refer to Group 9 for a discussion of aging management for the caulking. [Reference 2, Attachment 6]

Group 3 (external surface corrosion in an atmospheric environment) - Aging Mechanism Effects:

Crevice corrosion, general corrosion, and/or pitting are plausible for Group 3 components because some of the materials used in their construction are susceptible to these corrosion mechanisms when exposed to a wet environment. The aggressiveness of these corrosion mechanisms is particularly dependent on the overall corrosiveness of the environment and on the materials of construction. Refer to the discussion in Group 2 above for a detailed description of crevice corrosion, general corrosion, and pitting. [Reference 2, Attachment 6]

For Group 3 components, long-term exposure to a moist environment may result in localized and/or general area material loss and, if left unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. The areas where there are stagnant conditions and cracks or crevices, e.g., under the nut or in threaded areas of the stud, are the locations most susceptible to these corrosion mechanisms. All three of these ARDMs are plausible for carbon steel and alloy steel subcomponents. Crevice corrosion, general corrosion, and pitting are not plausible for subcomponents constructed of austenitic stainless steel due to the inherent corrosion resistance of the material and the non-aggressiveness of the environment. [Reference 2, Attachment 6]

Group 3 (external surface corrosion in an atmospheric environment) - Methods to Manage Aging:

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment and protecting the external surfaces with paint or other protective coating. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces. [Reference 2, Attachment 8]

Discovery: The effects of crevice corrosion, general corrosion, and pitting are detectable by visual inspection. Components that do not have insulation and are readily accessible can be observed periodically during routine walkdowns or inspections. Areas that are not readily accessible or that have insulation must be inspected as part of a dedicated program so that access can be provided and insulation removed as necessary. Corrective actions can be initiated if there is any evidence of corrosion identified during these inspections. [Reference 2, Attachment 8]

The external metal surfaces of some of the components and piping are covered by a protective coating, and observing that significant degradation has not occurred to this coating is an effective method to ensure that corrosion is being mitigated. Coatings degrade over time, allowing visual detection during normal operational walkdowns. The coating does not contribute to the intended function of the components; however, visually examining the coating for degradation provides an alert condition, which triggers corrective action prior to degradation that affects the component's ability to perform its intended function. The degradation of the protective coating that does occur can be discovered and managed by periodically inspecting the components and by carrying out corrective action as necessary. [Reference 2, Attachment 8]

Group 3 (external surface corrosion in an atmospheric environment) - Aging Management Programs:

Mitigation: The external metal surfaces of some of the components are covered by a protective coating that mitigates the effects of crevice corrosion, general corrosion, and pitting. The discovery programs discussed below ensure that the protective coatings of Group 3 components are maintained.

Discovery:

CCNPP System Walkdown Program

Calvert Cliffs Plant Engineering Guideline, PEG-7, "System Walkdowns," provides for discovery of corrosion and degraded paint by providing for system walkdowns by visual inspection, reporting the walkdown results, and initiating corrective action. Under this program, inspection items typically related to aging management include identifying poor housekeeping conditions (such as degraded paint), and identifying system and equipment stress or abuse such as thermal insulation damage, external leakage of fluids, etc. Non-insulated equipment in accessible areas of the No. 12 CST enclosure can be monitored for corrosion and degraded paint through these walkdowns. Conditions identified as adverse to quality are corrected in accordance with the CCNPP Corrective Actions Program. [Reference 23]

Under PEG-7, engineering personnel perform periodic walkdowns (typically monthly or as negotiated with the supervisor); walkdowns before, during, and after outages; and walkdowns related to a specific plant modification(s). These walkdowns have the following characteristics: [Reference 23, Section 5.0]

- Walkdowns are conducted at periodic intervals, as set by the Plant Engineering Guideline, based on system performance, operating conditions, etc.
- Walkdowns are generally performed by the assigned responsible engineer, who is familiar with the system and its condition. Signs of corrosion or effects of excessive loading would be detected by this individual.
- To assist in detecting such conditions, the System Walkdown guideline contains a checklist, which contains items related to aging of piping and components such as checking that coatings are applied and intact. Conditions observed during the walkdown are also recorded.
- The Plant Engineering Guideline on System Walkdowns requires that any unusual condition observed during the walkdown be recorded on the walkdown sheet and assistance obtained from design engineering in evaluating the impact of the unusual condition. Conditions that warrant further action are documented on an issue report and the site corrective action program tracks the status of corrective actions. [Reference 23]

Guideline PEG-7 promotes familiarity with the systems by the system engineers and provides extended attention to plant material condition beyond that afforded by operations and maintenance alone. As a result of experience gained, PEG-7 has been improved over time to provide guidance regarding specific standard activities that should be included in walkdowns.

CCNPP ARDI Program

Crevice corrosion, general corrosion, and pitting will be readily detectable for the Group 3 components through visual inspections. However, some of the components are in areas that are not readily accessible, such as the valve pit, or are covered by insulation. These components will be included in a new plant program to accomplish the needed inspections for corrosion. This program is considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program. [Reference 2, Attachment 8]

Corrective actions will be taken in accordance with the CCNPP Corrective Action Program and will ensure that the components will remain capable of performing their pressure boundary integrity function under all CLB conditions.

Group 3 (external surface corrosion in an atmospheric environment) - Aging Management Demonstration:

Based on the information presented above, the following conclusions can be reached with respect to general corrosion, crevice corrosion, and pitting of AFW System Group 3 components:

- The AFW System Group 3 components contribute to the system pressure boundary function and their integrity must be maintained under all CLB conditions.

- Crevice corrosion, general corrosion, and pitting are plausible ARDMs for this group of components and could result in material loss which, if left unmanaged, can lead to loss of pressure-retaining capability under CLB design loading conditions.
- Guideline PEG-7 provides for discovery of corrosion and degraded paint on uninsulated components in accessible areas by providing for visual inspection through system walkdowns, reporting the walkdown results, and initiating corrective action in accordance with the CCNPP Corrective Actions Program.
- The Group 3 components located in locations not readily accessible or covered by insulation will be included in the scope of an ARDI Program. Inspections will be performed and appropriate corrective action will be taken if significant corrosion is discovered.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting will be adequately managed for the AFW System Group 3 components such that they will be capable of performing their pressure boundary integrity function, consistent with the CLB, during the period of extended operation.

Group 4 (external surface corrosion of buried pipe) - Materials and Environment

Group 4 consists of piping that is buried in soil or embedded in concrete and whose external surfaces are subject to crevice corrosion, general corrosion, MIC, and pitting. The external surfaces of the piping are protected per standard industry practice with external coating and wrapping. A cathodic protection system is also in place for the buried pipe; however, no credit is taken for mitigation of corrosion. The buried pipe and fittings are constructed of carbon steel. [Reference 2, Attachments 4 and 6]

The two main headers penetrate horizontally into the Auxiliary Building through a blockout approximately 5 feet below grade. The blockout is filled with concrete. The concrete is sufficiently impermeable to water to protect the rebar, and would therefore similarly protect the embedded portion of the pipe. However, the protective coatings at the penetration interfaces may have been damaged during construction, which could allow moisture into these areas. [Reference 2, Attachment 6]

The pipes going to and from the valve pit in the tank farm also penetrate into a concrete structure below grade. In this case, the penetrations are caulked. However, the caulking below grade would not be expected to provide protection from moisture for 60 years and could, therefore, allow corrosion to take place on the exterior surfaces of the pipes inside the penetrations. [Reference 2, Attachment 6]

Group 4 (external surface corrosion of buried pipe) - Aging Mechanism Effects:

Crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting are plausible for Group 4 piping because the carbon steel material used in its construction is susceptible to these corrosion mechanisms when exposed to a wet environment and in electrical contact with a dissimilar metal. The aggressiveness of these corrosion mechanisms is particularly dependent on the overall corrosiveness of the environment and on the materials of construction. Refer to the discussion in Group 2 above for a detailed description of crevice corrosion, general corrosion, and pitting. [Reference 2, Attachment 6]

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate reducing bacteria, sulfur oxidizers, and iron oxidizing bacteria are most commonly associated with these corrosion effects. Microbiologically-induced corrosion most often results in pitting, followed by excessive deposition of corrosion products. Essentially all buried piping systems and most commonly used materials are susceptible to MIC. [Reference 2, Attachment 7]

Galvanic corrosion is an accelerated corrosion caused by dissimilar metals in contact in a conductive solution. It requires two dissimilar metals in physical or electrical contact, developed potential (material dependent) and a conducting solution. [Reference 2, Attachment 7] For this piping section, the carbon steel pipe is at a different voltage potential than the steel rebar in the concrete surrounding sections of this pipe. In a moist, conductive soil environment, this could lead to galvanic corrosion with the pipe sacrificing material at locations where the protective coating has holidays (thin spots, skipped areas, or where coating degradation has occurred) and is in contact with the wet soil.

For Group 4 components, long-term exposure to a moist environment may result in localized and/or general area material loss and, if left unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Soil resistivity (or conductivity), chloride and sulfate presence, oxygen content and soil aeration, pH, moisture content of the soil and wet/dry cycles, and microbe activity affect these ARDMs. [Reference 2, Attachment 6] Damaged protective coatings/wrappings, holidays or disbonded areas in the coating/wrapping, and leakage around caulking can allow these ARDMs to develop on the exterior surfaces of the pipe and at the interface where the pipes penetrate the concrete walls. All of these ARDMs are plausible for carbon steel piping. [Reference 2, Attachment 8]

Group 4 (external surface corrosion of buried pipe) - Methods to Manage Aging:

Mitigation: The effects of corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment by protecting the external surfaces with protective wrapping/coatings and application of cathodic protection. Wrapping/coatings serve as a protective layer, preventing moisture, oxygen, and microbes from directly contacting the steel surfaces. [Reference 2, Attachment 8]

Discovery: The effects of crevice corrosion, general corrosion, MIC, and pitting are detectable by visual inspection. The wrapping and coating do not contribute to the intended function of the buried piping. However, they play a role in mitigating corrosion of buried and embedded piping. Visually examining the wrapping and coating on the buried piping for evidence of degradation provides an alert condition, which triggers corrective action before degradation that affects the underground piping's ability to perform its intended function could occur. The corrosion that does occur can be discovered and managed by inspecting the piping at areas where the wrapping has holidays or disbonded areas. Then repairs can be made to the piping or wrapping as required. [Reference 2, Attachment 8]

Group 4 (external surface corrosion of buried pipe) - Aging Management Programs:

Mitigation: The external surfaces of buried piping are protected from contact with the soil or concrete by protective wrapping/coatings. This design feature mitigates the effects of crevice corrosion, general corrosion, MIC, and pitting. Although the piping is further protected with a cathodic protection system, it is not credited for mitigating these ARDMs. The discovery program discussed below ensures that the protective coatings of Group 4 components are maintained. [Reference 2, Attachment 8]

Discovery:

CCNPP AFW Buried Pipe Inspection Program

A new program for buried pipe will include AFW Group 4 piping and will provide assurance that the piping will remain capable of maintaining the system pressure boundary under all CLB conditions. Representative samples of buried piping will be selected for inspection to ensure that the pipe wrapping/coatings are adequately protecting the pipe from the external environment. Any evidence of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting will initiate corrective actions in accordance with the CCNPP Corrective Actions Program. [Reference 2, Attachment 8]

Group 4 (external surface corrosion of buried pipe) - Aging Management Demonstration:

Based on the information presented above, the following conclusions can be reached with respect to crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting of AFW System Group 4 piping:

- The AFW System Group 4 piping contributes to the system pressure boundary function and its integrity must be maintained under all CLB conditions.
- Crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting are plausible ARDMs for the buried piping and could result in material loss which, if left unmanaged, can lead to loss of pressure-retaining capability under CLB design loading conditions.
- The external surfaces of the piping are protected according to standard industry practice with external coating and wrapping.
- Through a new CCNPP AFW Buried Pipe Inspection Program, corrosion would be discovered through visual inspections of representative piping sections and corrective actions will be taken as necessary.

Therefore, there is reasonable assurance that the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting will be adequately managed for the AFW System Group 4 piping such that it will be capable of performing its pressure boundary integrity function, consistent with the CLB, during the period of extended operation.

Group 5 (internal surface corrosion in a steam environment) - Materials and Environment:

Group 5 consists of components that are exposed to an internal environment of chemistry-controlled steam below 600°F, and that are subject to crevice corrosion, general corrosion, pitting, and erosion corrosion. The device types that have at least one component with Group 5 attributes include the governor valve, turbine, and control valve (turbine throttle/stop valves). The subcomponents in these device types exposed to steam conditions are constructed of the following materials: [Reference 2, Attachments 4 and 6]

- governor valve - alloy steel valve body and bonnet with an Inconel 718 stem, chromium-molybdenum alloy steel studs, and carbon steel nuts;
- turbine - carbon steel turbine case and bypass elbow with a cast iron gland case, a stainless steel lube oil cooler, carbon steel nuts, and alloy steel shaft, jet plug, studs, and gland cap; and
- control valve - cast alloy steel body, cover, and stuffing box with Nitralloy 135 bushings and pilot valve, carbon-molybdenum nuts, low alloy steel studs, and carbon steel plugs.

These components are normally in a standby mode, but may be put into operation during plant heatup, plant cooldown, steam generator filling, and monthly testing. During those times, the components are subject to induction of steam. Condensation of the steam during system warmup and after system cooldown is minimized by draining through the trip/throttle valve leakoffs, turbine exhaust, and turbine steam ring drains. Any remaining moisture/dampness, which is usually from the main steam system (auxiliary steam may be used if the main steam pressure is low), is from a chemistry-controlled source that minimizes corrosion and non-condensible gases. [Reference 2, Attachment 6]

Group 5 (internal surface corrosion in a steam environment) - Aging Mechanism Effects:

Carbon steel, many alloy steels, and cast iron are susceptible to crevice corrosion, general corrosion, and pitting in a humid or wet environment. These ARDMs are plausible for Group 5 components because of the exposure to a wet environment following operation. The aggressiveness of these corrosion mechanisms is particularly dependent on the overall corrosiveness of the environment and on the materials of construction. All three of these ARDMs are plausible for the subcomponents constructed of carbon steel, alloy steel, cast iron, Inconel 718, or Nitralloy 135. Crevice corrosion and pitting are plausible for subcomponents constructed of stainless steel or bronze alloy materials. General corrosion is not plausible for these components because the materials are resistant to general corrosion. If left unmanaged, crevice corrosion, general corrosion, and pitting could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 2, Attachment 6] Refer to the discussion in Group 2 above for a detailed description of crevice corrosion, general corrosion, and pitting.

Erosion corrosion is a plausible ARDM for all of the internal subcomponents of the Group 5 components, with the exceptions discussed below, because they are exposed to high velocity steam during operation and condensation/dampness during standby. Erosion corrosion of the stainless steel turbine lube oil cooler is not plausible because the stainless steel is resistant to erosion corrosion and not exposed to steam flow. The governor valve oil cooler tubes and end cap are also not susceptible because the component design, materials, and internal environment do not perpetuate this ARDM. [Reference 2, Attachment 6]

Erosion corrosion is the increased rate of attack on a metal due to the relative movement between a corrosive fluid and the metal surface. Erosion is a mechanical action of a fluid and/or particulate matter on a metal surface, without the influence of corrosion. The corrosive process is accelerated because of the erosion destruction of the protective oxide film, which results in chemical attack or dissolution of the underlying metal. Erosion corrosion failures can occur in a relatively short time. The periodic testing of the system using high velocity steam may remove general corrosion products and the protective oxide film, resulting in continued general corrosion and erosion/corrosion. The aging effects can be grooves, gullies, waves, holes, or valleys in the material surface. If left unmanaged, erosion corrosion could eventually result in the loss of pressure-retaining capability under CLB design loading conditions. [Reference 2, Attachments 6 and 7]

Group 5 (internal surface corrosion in a steam environment) - Methods to Manage Aging:

Mitigation: Controlling steam chemistry will minimize the concentration of corrosive impurities (e.g., chlorides, sulfates, oxygen). By maintaining water chemistry within acceptable limits, all types of corrosion can be mitigated. [Reference 2, Attachment 8]

Discovery: The effects of corrosion (crevice corrosion, general corrosion, pitting, and erosion corrosion) on AFW System Group 5 components can be discovered and monitored through non-destructive examination techniques such as visual inspections. [Reference 2, Attachment 8] Representative samples of susceptible locations can be used to assess the need for additional inspections at less susceptible locations. Based on component geometry and fluid flow conditions, areas most likely to experience corrosion can be determined and evaluated. [Reference 2, Attachment 6]

Group 5 (internal surface corrosion in a steam environment) - Aging Management Programs:

Mitigation:

CCNPP Secondary Chemistry Specifications and Surveillance Program

The CCNPP Secondary Chemistry Specifications and Surveillance Program has been established to: minimize impurity ingress to plant systems; reduce corrosion product generation, transport, and deposition; improve integrity and availability of plant systems; and extend component and plant life. Control of fluid chemistry minimizes the corrosiveness of the environment for AFW System Group 5 components, and thereby minimizes the rate and effects of corrosion. [Reference 10, Section 6.1.A] Refer to the Group 2 discussion on aging management programs for a detailed discussion of the Secondary Chemistry Program. The corrective actions taken as part of this program will help ensure that Group 5 components will remain capable of performing their intended functions under all CLB conditions.

Discovery: The occurrence of crevice corrosion, general corrosion, pitting, and erosion corrosion is expected to be limited and is unlikely to affect the intended function of the governor valves, turbines, and turbine throttle/stop valves due to the control of secondary chemistry. To ensure that these components are not experiencing significant degradation, and to ensure that corrective actions are taken if they are, periodic visual inspections will be conducted. The turbine will be inspected as part of the periodic overhaul that is performed in accordance with the CCNPP Preventive Maintenance Program. The governor valve and turbine throttle/stop valves will be included in a new ARDI Program. The corrective actions taken as part of these programs will ensure that Group 5 components will remain capable of performing their intended functions under all CLB conditions. [Reference 2, Attachment 8]

CCNPP Preventive Maintenance Program

The CCNPP Preventive Maintenance Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. The program covers all preventive maintenance activities for nuclear power plant structures and equipment within the plant, including the AFW System components within the scope of license renewal. It is based on the INPO documents listed as References 24 through 26. [Reference 27]

The existing CCNPP Preventive Maintenance Program includes tasks that require a periodic overhaul of the AFW pump turbines. In accordance with CCNPP Technical Procedure TURB-01, "Auxiliary Feedwater Pump Turbine Overhaul," the turbine is disassembled and then inspected for damage. Measurements are taken to assure critical tolerances are within acceptance criteria. Specific subcomponents are inspected for wear, erosion, pitting, and/or surface cracking. Unsatisfactory inspection results are recorded and evaluated. Corrective actions are initiated in accordance with the CCNPP Corrective Actions Program, if necessary. [References 28 and 29] Past inspections of AFW pump turbines during overhauls have revealed no defects such as cracks or corrosion. The AFW pump turbines are in good condition.

The Preventive Maintenance Program has been evaluated by the NRC as part of their routine licensee assessment activities. The plant Maintenance Program also has had numerous levels of BGE management review, all the way down to the specific implementation procedures. For example, there are specific responsibilities assigned to BGE personnel for evaluating and upgrading the Preventive Maintenance Program. [Reference 27] These assessments and controls provide reasonable assurance that the Preventive Maintenance Program will continue to be an effective method of monitoring the effects of corrosion and fatigue, thus ensuring that the AFW pump turbine will remain capable of performing its pressure boundary function under all CLB loading conditions.

CCNPP ARDI Program

Corrosion will be readily detectable for the Group 5 components through visual inspections. The governor valves and turbine throttle/stop valves will be included in a new ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. The ARDI Program will discover and manage crevice corrosion, general corrosion, pitting, and erosion corrosion that may be occurring on these components. Corrective actions will be taken in accordance with the CCNPP Corrective Action Program and will ensure that the components will remain capable of performing the system pressure boundary integrity function under all CLB conditions. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program. [Reference 2, Attachment 8]

Group 5 (internal surface corrosion in a steam environment) - Aging Management Demonstration:

Based on the information presented above, the following conclusions can be reached with respect to corrosion of AFW System Group 5 components:

- The AFW System governor valves, turbines, and control valves (i.e., turbine throttle/stop valves) contribute to the system pressure boundary function and their integrity must be maintained under all CLB conditions.

- Crevice corrosion, general corrosion, pitting, and erosion corrosion are plausible ARDMs for the Group 5 components and could result in material loss which, if left unmanaged, can lead to loss of pressure-retaining capability under CLB design loading conditions.
- The CCNPP Secondary Chemistry Specifications and Surveillance Program controls the Main Steam System fluid chemistry to minimize the corrosiveness of the environment for the AFW System components.
- The occurrence of these ARDMs is expected to be limited and not likely to affect the intended function of the Group 5 components due to the control of fluid chemistry and the limited operation.
- There is an existing turbine overhaul that is periodically performed, which includes inspections for corrosion and other degradation. If the inspections reveal damage, corrective actions are initiated in accordance with the CCNPP Corrective Actions Program, as necessary.
- To provide the additional assurance needed to conclude that the effects of corrosion are being effectively managed, the governor valves and turbine throttle/stop valves will be included in the scope of an ARDI Program. Inspections will be performed and appropriate corrective action will be taken if significant corrosion is discovered.

Therefore, there is a reasonable assurance that the effects of corrosion will be adequately managed for the AFW System governor valves, turbines, and turbine throttle/stop valves such that they will be capable of performing their pressure boundary integrity function, consistent with the CLB, during the period of extended operation.

Group 6 (external surface corrosion of the turbine-driven pump) - Materials and Environment

Group 6 consists of the turbine-driven pump external surfaces that are subject to crevice corrosion and pitting due to stuffing box leakoff. The affected subcomponents include the split gland and external screws/studs and nuts. All of these subcomponents are constructed of stainless steel. [Reference 2, Attachments 4 and 6]

The Group 6 turbine-driven pump subcomponents are exposed to a wet environment due to leakage of the stuffing box. Small volumes of water will collect in cracks and crevices and become stagnant, which is conducive to corrosion because harmful impurities can become concentrated. The source of the water is from the AFW System, which is supplied water from the CSTs. The water in the CSTs is monitored and controlled through the Secondary Chemistry Program. [Reference 2, Attachment 6]

Group 6 (external surface corrosion of the turbine-driven pump) - Aging Mechanism Effects:

Crevice corrosion and pitting are plausible for Group 6 components because of the geometry of the subcomponents and the stagnant water conditions. Leakage from the stuffing box can collect in cracks, crevices, and between subcomponents that can cause harmful impurities in the water to concentrate, thereby creating an environment conducive to these ARDMs. Industry experience has shown that these corrosion mechanisms are plausible. For Group 6 subcomponents, long-term exposure to the wet environment may result in small cracks and/or pits. If left unmanaged, the resulting material loss could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Refer to the discussion on aging mechanism effects in Group 2 for a detailed discussion of crevice corrosion and pitting. [Reference 2, Attachment 6]

Group 6 (external surface corrosion of the turbine-driven pump) - Methods to Manage Aging:

Mitigation: The effects of crevice corrosion and pitting cannot be completely prevented, but they can be mitigated by minimizing the exposure of the turbine-driven pumps to an aggressive environment. Maintaining an internal environment of purified water, with impurities maintained at low levels during normal plant operation, minimizes to some extent the buildup of harmful impurities in crevices, and thereby minimizes corrosion reactions when this water leaks onto external surfaces. The initial formation of a passive oxide layer (magnetite) also protects the component surfaces by minimizing the exposure of bare metal to water. [Reference 2, Attachment 6]

Discovery: The occurrence of crevice corrosion and pitting is expected to be limited, and is unlikely to affect the intended function of the AFW System turbine-driven pump, due to the control of fluid chemistry, inspections of the pump subcomponents during periodic overhauls, and gland follower adjustment. However, to assure that these ARDMs are not causing significant degradation of the external surfaces of the turbine-driven pump, they can be visually inspected on a periodic basis to detect crevice corrosion or pitting. Corrective actions can be initiated if there is any evidence of corrosion identified during these inspections. [Reference 2, Attachment 8]

Group 6 (external surface corrosion of the turbine-driven pump) - Aging Management Programs:

Mitigation:

CCNPP Secondary Chemistry Specifications and Surveillance Program

The CCNPP Secondary Chemistry Specifications and Surveillance Program has been established to: minimize impurity ingress to plant systems; reduce corrosion product generation, transport, and deposition; improve integrity and availability of plant systems; and extend component and plant life. Control of fluid chemistry minimizes the concentration of corrosive impurities (chlorides, sulfates) for external surfaces of the turbine-driven pump due to leakage, and minimizes the rate and effects of corrosion. [Reference 10, Section 6.1.A] Refer to the Group 2 discussion on aging management programs for a detailed discussion of the Secondary Chemistry Program. The corrective actions taken as part of this program will help ensure that the turbine-driven pump will remain capable of performing its intended functions under all CLB conditions.

Discovery: For the external surfaces of the turbine-driven pump, crevice corrosion and pitting can be readily detected through visual inspections. However, due to the control of fluid chemistry, inspections of the pump subcomponents during overhauls, and gland follower adjustment, the occurrence of crevice corrosion and pitting is expected to be limited and not likely to affect the intended function of the turbine-driven pump. However, since the overhauls are not performed on a specific frequency, an additional inspection performed on a periodic basis can provide the additional assurance needed to conclude that the effects of these ARDMs are being effectively managed for the period of extended operation. [Reference 2, Attachment 8]

CCNPP System Walkdown Program

Guideline PEG-7 provides for discovery of corrosion and degraded paint by providing for periodic system walkdowns by visual inspection, reporting the walkdown results, and initiating corrective action. Under this program, inspection items typically related to aging management include identifying poor housekeeping conditions (such as degraded paint) and identifying system and equipment stress or abuse, such as thermal insulation damage, external leakage of fluids, etc. This program, along with the overhauls performed on the pump, will provide reasonable assurance that significant degradation will be discovered and corrected. Refer to the discussion on aging management programs in Group 3 for further details on the System Walkdown Program. Conditions identified as adverse to quality are corrected in accordance with the CCNPP Corrective Actions Program. The corrective actions taken will ensure that the turbine-driven pump will remain capable of performing the system pressure boundary integrity function under all CLB conditions. [Reference 23]

Group 6 (external surface corrosion of the turbine-driven pump) - Aging Management Demonstration:

Based on the information presented above, the following conclusions can be reached with respect to crevice corrosion and pitting of the external surfaces of the turbine-driven pump:

- The AFW System turbine-driven pump contributes to the system pressure boundary function and its integrity must be maintained under all CLB conditions.
- Crevice corrosion and pitting are plausible ARDMs for the external surfaces of this component and could result in material loss which, if left unmanaged, can lead to loss of pressure-retaining capability under CLB design loading conditions.
- The CCNPP Secondary Chemistry Specifications and Surveillance Program controls the CSTs' fluid chemistry, which minimize the corrosiveness of the water leaking onto the external surfaces of the turbine-driven pump.
- The occurrence of crevice corrosion and pitting is expected to be limited and not likely to affect the intended function of the turbine-driven pump because of the general resistance of stainless steels to corrosion.
- Guideline PEG-7 provides for discovery of corrosion and degraded paint by providing for visual inspection through periodic system walkdowns, reporting the walkdown results, and initiating corrective action in accordance with the CCNPP Corrective Actions Program.

Therefore, there is reasonable assurance that the effects of crevice corrosion and pitting will be adequately managed for the external surfaces of the turbine-driven pump such that they will be capable of performing their pressure boundary integrity function, consistent with the CLB, during the period of extended operation.

Group 7 - (wear and elastomer degradation of solenoid-operated valves) - Materials and Environment:

The subcomponent of the solenoid-operated valves that is subject to wear and elastomer degradation is the seat, which is constructed of ethylene propylene. The subcomponent of the solenoid-operated valves that is subject to wear only is the disk holder assembly, which is constructed of plastic. The internal surfaces of the solenoid-operated valves are exposed to compressed air, which is normally clean of debris, oil-free, and dry. [Reference 2, Attachments 4, 5, and 6]

Group 7 - (wear and elastomer degradation of solenoid-operated valves) - Aging Mechanism Effects:

Wear results from relative motion between two surfaces; from the influence of hard, abrasive particles or fluid stream; and from small vibratory or sliding motions under the influence of corrosive environment. The most common result of wear is damage to one or both surfaces involved in the contact. Wear rates increase as worn surfaces experience higher contact stresses than the surfaces of the original geometry. [Reference 2, Attachment 7]

Wear is a plausible ARDM for solenoid-operated valves because of the relative motion between their parts and the cyclic nature of operation. Wear can result in material loss and subsequent leakage of SR compressed air. The parts of concern are related to the seating of the valve, i.e., the ethylene propylene sent and the plastic disk holder assembly. The soft seat could wear to the point where leakage could prematurely deplete the two-hour supply of compressed air in the accumulators that is needed if the air compressors lose power. [Reference 2, Attachment 6] If unmanaged, wear could eventually result in the loss of pressure-retaining capability of the Compressed Air System under CLB design loading conditions.

An elastomer is a material that can be stretched to significantly greater than original length and, upon immediate release of the stress, will return with force to approximately its original length. When an elastomer ages, there are three mechanisms primarily involved:

1. Scission - the process of breaking molecular bonds, typically due to ozone attack, UV light, or radiation;
2. Crosslinking - the process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat or curing; and
3. Compound ingredient evaporation, leaching, mutation, etc.

Natural aging tests indicate that where there is a significant property change in a elastomer, it appears that it occurs within the first five to ten years after initial formulation/curing. [Reference 2, Attachment 7]

For valve seating applications, elastomers generally harden as they age making sealing more difficult. Elastomer degradation of solenoid-operated valves is plausible because the elastomer seat is exposed to moderate heat, oxygen, ozone, and operating stresses. [Reference 2, Attachments 6 and 7] If unmanaged, elastomer degradation could eventually result in the loss of pressure-retaining capability of the Compressed Air System under CLB design loading conditions.

Group 7 - (wear and elastomer degradation of solenoid-operated valves) - Methods to Manage Aging:

<u>Mitigation:</u> Since elastomer degradation is caused by exposure of susceptible subcomponents to environmental conditions that are not feasible to control (e.g., heat, oxygen, ozone), there are no reasonable methods to mitigate its effects. Since wear is caused by relative motion between susceptible subcomponents of these components, and it is not feasible to limit valve operation, there are no reasonable

methods to mitigate its effects. The discovery method discussed below is deemed adequate to manage these ARDMs. [Reference 2, Attachment 8]

Discovery: A visual inspection of the internals of valves can be performed to detect degradation of the seating surface of the valves. The results of the inspections can be evaluated to determine if component or subcomponent replacement is warranted, and if so, to determine an appropriate replacement schedule. Corrective actions can be initiated accordingly. [Reference 2, Attachment 8]

Group 7 - (wear and elastomer degradation of solenoid-operated valves) - Aging Management Programs:

Mitigation: There are no mitigation programs credited for wear or elastomer degradation of the solenoid-operated valves.

Discovery: The solenoid-operated valves will be included in a new ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. The ARDI Program will discover and manage the wear and elastomer degradation that may be occurring on these components. Corrective actions will be taken in accordance with the CCNPP Corrective Action Program and will ensure that the components will remain capable of performing the system pressure boundary integrity function under all CLB conditions. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program. [Reference 2, Attachment 8]

Group 7 - (wear and elastomer degradation of solenoid-operated valves) - Demonstration of Aging Management:

Based on the information presented above, the following conclusions can be reached with respect to wear and elastomer degradation of the Group 7 solenoid-operated valves of the AFW System:

- The solenoid-operated valves contribute to the pressure boundary function and their integrity must be maintained under all CLB conditions.
- Wear is a plausible ARDM because of the relative motion between subcomponent parts and the soft seat and hard plastic materials that are in contact. Elastomer degradation is a plausible ARDM because subcomponents of this group are exposed to moderate heat, oxygen, ozone, and operating stresses, which over a long period of time will cause their degradation. If left unmanaged, wear and elastomer degradation could eventually result in the loss of pressure-retaining capability of Group 7 components under CLB design loading conditions.
- The solenoid operated pilot valves will be included in the scope of an ARDI Program. Inspections will be performed and appropriate corrective action will be taken if significant wear or elastomer degradation is discovered.

Therefore, there is reasonable assurance that the effects of wear and elastomer degradation will be adequately managed for the seating surfaces of the solenoid-operated valves such that they will be capable of performing their pressure boundary integrity function, consistent with the CLB, during the period of extended operation.

Group 8 (general corrosion of control valve operators) - Materials and Environment

Group 8 consists of control valve operators that are exposed to a compressed air environment and whose internal surfaces are subject to general corrosion. The subcomponents in these valve operators that provide the pressure boundary function and are exposed to compressed air are constructed of carbon steel (some are zinc plated), cast iron, brass, and bronze. [Reference 2, Attachments 4 and 6]

The internal environment for the control valve operators is normally compressed air supplied by the instrument air compressors. The instrument air is very dry, filtered, and oil-free air. Particle size, dew point and oil hydrocarbons are controlled for the instrument air supply in accordance with Instrument Society of America (ISA) standard ISA-S-7.3, "Quality Standard for Instrument Air." The dew point, which is a measurement of air moisture content, is normally maintained at -40°F at 100 psig. This dew point is well below the air quality standard of at least 18ºF below the minimum local recorded ambient temperature at the plant site. [References 1, 30, and 31]

Because the plant air or saltwater air compressors can be used as a backup to the instrument air compressors if they become unavailable, occasionally air from either the plant air or saltwater air compressors may enter the system. Additionally, the saltwater air compressors are run for a brief period of time each month for testing. The PA Subsystem air compressors use a moisture separator, which removes moisture in the air. The saltwater air compressors have an aftercooler, which cools the compressed air and condenses moisture that passes to the receiver where it is drained by an automatic valve. Based on the design and limited operation of these backup systems, perturbations in air quality outside of accepted industry air quality standards (dry, filtered, and oil-free) will be limited. [References 32 through 36]

Group 8 (general corrosion of control valve operators) - Aging Mechanism Effects:

General corrosion is plausible for Group 8 control valve operators because some of the materials used in their construction are susceptible to these corrosion mechanisms when exposed to a moist environment. The aggressiveness of these corrosion mechanisms is particularly dependent on the overall corrosiveness of the environment and on the materials of construction. General corrosion is plausible for the pressure-retaining subcomponents constructed of carbon steel or cast iron. It is not plausible for those pressure-retaining subcomponents constructed of brass or bronze because the materials are resistant to general corrosion. Refer to the discussion in Group 2 above for a detailed description of general corrosion. [Reference 2, Attachment 6]

Group 8 (general corrosion of control valve operators) - Methods to Manage Aging:

Mitigation: The effects of general corrosion cannot be completely prevented, but they can be mitigated by minimizing the exposure of metal surfaces to a moist environment. Keeping the air quality, i.e., dewpoint, within accepted industry standards can help mitigate general corrosion by minimizing the possibility of moisture in the control valve operators. [Reference 2, Attachment 8]

The AFW System control valves are supplied with compressed air from the Instrument Air Subsystem. The air quality of the Instrument Air Subsystem is normally maintained in accordance with industry standards for moisture (dewpoint) and particulate concentrations. Continued maintenance of Instrument Air Subsystem air quality to industry standards will ensure minimal component degradation resulting from moisture or from rust particles. The use of air dryers and filters maintains the air quality within acceptable limits. In order to assure that the compressed air quality remains within acceptable limits, the air quality should be periodically checked and compared against the industry standards. [Reference 2, Attachment 8] If testing shows a reduction in air quality, corrective actions can be initiated to return the air quality to normal.

The possibility of occasional exposure to slight moisture exists from operation of the saltwater air compressors because there is no dryer for this supply. The exposure to moisture is minimal and short term, and is not expected to result in significant levels of degradation of the carbon steel components. An inspection performed on the piping immediately downstream of the saltwater air compressors, where the worst case of general corrosion is expected, revealed only very light surface rust on the inside of each piece. After more than 20 years in operation, approximately 60% of the pipe interior contained no rust and appeared similar to the inside of new pipe. Thickness measurements showed that the wall thickness averaged only 0.001 inch less than the nominal thickness of 0.179 inch. [Reference 2, Attachment 8] Since air in the Instrument Air and Saltwater Air Subsystems is normally very dry and there is so little corrosion evident after more than 20 years of operation, continued maintenance of the air quality is deemed an adequate aging management technique for general corrosion control in components supplied with compressed air from the Instrument Air Subsystem.

Discovery: The occurrence of general corrosion is expected to be limited and is unlikely to affect the intended function of the AFW System Group 8 components due to the control of compressed air dryness. The mitigation technique described above is deemed adequate for managing the effects of general corrosion of AFW System control valve operators. [Reference 2, Attachment 8]

Group 8 (general corrosion of control valve operators) - Aging Management Programs:

Mitigation:

CCNPP Preventive Maintenance Program

The CCNPP Preventive Maintenance Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. The program covers all preventive maintenance activities for nuclear power plant structures and equipment within the plant, including the control of air dryness in the Compressed Air System. [Reference 27] Refer to the Group 5 discussion on aging management programs for a detailed discussion of the Preventive Maintenance Program.

Calvert Cliffs initiated a Preventive Maintenance Task following a review of recommendations in Significant Operating Event Report SOER 88-01. This task checks the Instrument Air Subsystem air quality at three locations in the system; at the air dryer outlet, at the furthest point from the dryer, and at the approximate midpoint between these locations. Measurements of dew point and particulate count are taken periodically at these locations. This Preventive Maintenance Task is automatically scheduled and implemented in accordance with SR Preventive Maintenance Program procedures. [References 27 and 37]

According to procedure, dew point data and particulate sample results are reviewed and evaluated in accordance with SOER 88-01. SOER 88-01 recommends maintaining the air quality within the requirements of standard ISA-S-7.3. Standard ISA-S7.3 recommends limits for maximum particle size, dew point temperature, and oil content. If the air quality is determined to be abnormal, corrective actions are initiated to return the air quality to normal, and the condition of the dependent loads' internals are evaluated, as appropriate. [References 37 and 38]

Discovery: Since the mitigation techniques are deemed adequate for managing general corrosion, no discovery techniques are credited.

Group 8 (general corrosion of control valve operators) - Aging Management Demonstration:

Based on the information presented above, the following conclusions can be reached with respect to general corrosion of AFW System Group 8 components:

- The AFW System Group 8 control valve operators contribute to the system pressure boundary function and their integrity must be maintained under all CLB conditions.
- General corrosion is a plausible ARDM for this group of components and could result in material loss which, if left unmanaged, can lead to loss of pressure-retaining capability under CLB design loading conditions.
- The compressed air supplied to these components is normally very dry air. Inspections of the Compressed Air System piping showed there is negligible corrosion in that piping after over 20 years of operation.
- The air quality, including air dryness, continues to be monitored and evaluated against the air quality requirements of standard ISA-S-7.3 through the Preventative Maintenance Program. If the air quality is abnormal, corrective actions are initiated to return the air quality to normal and the condition of the dependent loads' internals is evaluated, as appropriate.
- Based on the ongoing air quality controls and the past operating history, the occurrence of general corrosion is expected to be limited and is unlikely to affect the intended function of the Group 8 control valve operators.

Therefore, there is reasonable assurance that the effects of general corrosion will be adequately managed for the AFW System Group 8 control valve operators such that they will be capable of performing their pressure boundary integrity function, consistent with the CLB, during the period of extended operation.

Group 9 - (elastomer degradation of No. 12 CST perimeter seal) - Materials and Environment:

The No. 12 CST perimeter seal is a caulking material consisting of an elastomer. The caulking is exposed to atmospheric conditions, but is protected from the direct effects of the weather by the stainless steel tank's protective enclosure. [Reference 2, Attachments 4 and 6]

Group 9 - (elastomer degradation of No. 12 CST perimeter seal) - Aging Mechanism Effects:

elastomers generally harden as they age, making sealing more difficult. Elastomer degradation of the No. 12 CST perimeter seal is plausible because the elastomer caulking is exposed to moderate heat, oxygen, and ozone. Over time, the caulking will become embrittled and lose its capability to prevent moisture from entering at the ring foundation interface with the stainless steel tank. Refer to the discussion on aging mechanism effects for Group 7 for a detailed description of elastomer degradation. [Reference 2, Attachments 6 and 7]

Group 9 - (elastomer degradation of No. 12 CST perimeter seal) - Methods to Manage Aging:

Mitigation: Since elastomer degradation is caused by exposure of susceptible subcomponents to environmental conditions, which are not feasible to control (e.g., heat, oxygen, ozone), there are no reasonable methods to mitigate its effects. The discovery method discussed below is deemed adequate to manage this ARDM. [Reference 2, Attachment 8]

Discovery: Caulking and sealant does not contribute to the intended function of the No. 12 CST. However, it plays a role in mitigating corrosion of the tank bottom by providing a moisture barrier. Periodic visual inspections can be made of the No. 12 CST perimeter seal to detect degradation of the caulking. Based on the results of the inspections, the caulking can be repaired or replaced in order to maintain the sealing capabilities. [Reference 2, Attachment 8]

Group 9 - (elastomer degradation of No. 12 CST perimeter seal) - Aging Management Programs:

Mitigation: There are no mitigation programs credited for elastomer degradation of the CST perimeter seal. However, maintenance of the perimeter seal, as discussed below, is credited for mitigating external corrosion of the bottom of the No. 12 CST.

Discovery: Aging management of the No. 12 CST perimeter seal will be conducted consistent with the management of caulk and sealants identified in the aging management of structures in Section 3.3 of the BGE LRA. A new CCNPP Caulking and Sealant Inspection Program will provide requirements and guidance for the identification, inspection frequencies, and acceptance criteria of caulking and sealant used throughout the plant to ensure that their condition is maintained at a level that allows them to perform their intended function. [Reference 2, Attachment 8]

The caulking, sealants, and expansion joints throughout the plant that are not fire barriers are typically replaced upon identification of their degraded condition. A new CCNPP Caulking and Sealant Inspection Program will include the No. 12 CST perimeter seal to ensure that its condition is maintained at a level that ensures it continues to provide an adequate moisture barrier through the renewal period. The new program will establish acceptance criteria for the seal and will require a baseline inspection to determine the material condition. If unacceptable degradation exists, corrective actions will be taken. A technical basis will be developed for determining the periodicity of future inspections.

Group 9 - (elastomer degradation of No. 12 CST perimeter seal) - Demonstration of Aging Management:

Based on the information presented above, the following conclusions can be reached with respect to elastomer degradation of the No. 12 CST perimeter seal of the AFW System:

- Caulking and sealant do not contribute to the intended function of the No. 12 CST. However, it plays a role in mitigating corrosion of the tank bottom by providing a moisture barrier, thereby helping to maintain the pressure boundary function of the No. 12 CST. The moisture barrier integrity of this perimeter seal must be maintained during the period of extended operation.

- elastomer degradation is a plausible ARDM because the No. 12 CST perimeter seal caulking is exposed to moderate heat, oxygen, and ozone, which can cause the caulking to embrittle and crack. If left unmanaged, elastomer degradation could eventually result in the loss of moisture retaining capability of the No. 12 CST perimeter seal.
- A new CCNPP Caulking and Sealant Inspection Program will provide requirements and guidance for the identification, inspection, and maintenance of caulking and sealant used throughout the plant, including the No. 12 CST perimeter seal, to ensure that their condition is maintained at a level that allows them to perform their intended function.

Therefore, there is reasonable assurance that the effects of elastomer degradation on the No. 12 CST perimeter seal will be managed in such a way as to maintain the components' moisture barrier integrity, consistent with the CLB, during the period of extended operation.

5.1.3 Conclusion

The aging management programs discussed for the AFW System are listed in the following table. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects in such a way that the intended functions of the components of the AFW System will be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 5.1-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE AUXILIARY FEEDWATER SYSTEM

	Program	Credited As
Existing	CCNPP Demineralized Water Chemistry Specifications and Surveillance Program Procedure CP-202, "Specifications and Surveillance- Demineralized Water, Safety Related Battery Water, Well Water Systems, and Acceptance Criteria for On-line Monitors"	• Mitigating the effects of crevice corrosion, general corrosion, and pitting of the internal surfaces of AFW System check valves located at the interface with the Chemical Addition System. (Group 2)
Existing	CCNPP Secondary Chemistry Specifications and Surveillance Program Procedure CP-217, "Specifications and Surveillance: Secondary Chemistry"	Mitigating the effects of crevice corrosion, general corrosion, and pitting by controlling CST water chemistry to minimize the corrosiveness of the environment for the internal surfaces of AFW System components. (Group 2) Mitigating the effects of corrosion for the internal surfaces of governor valves, turbines, and control valves with steam as the internal environment. (Group 5) • Mitigating the effects of crevice corrosion and pitting for the external surfaces of the turbine-driven pump due to stuffing box leakoff. (Group 6)
Existing	CCNPP System Walkdown Program Plant Engineering Guideline, PEG-7, "System Walkdowns"	Discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the external surfaces of uninsulated and readily accessible AFW components located in the No. 12 CST enclosure. (Group 3) • Discovery and management of the effects of crevice corrosion and pitting for the external surfaces of the turbine-driven pump due to stuffing box leakoff. (Group 6)
Existing	CCNPP Preventive Maintenance Program Repetitive Tasks 10191024 and 20191022, “Check Instrument Air Quality at System Low Points”	• Mitigation and management of the effects of general corrosion of the internal surfaces of control valve operators exposed to compressed air. (Group 8)

TABLE 5.1-3
(continued)

LIST OF AGING MANAGEMENT PROGRAMS FOR THE AUXILIARY FEEDWATER SYSTEM

	Program	Credited As
Existing	CCNPP Preventive Maintenance Program Repetitive Tasks 10362000, 10362001, 20362018, 20362019 utilizing procedure TURB-01, "Auxiliary Feedwater Pump Turbine Overhaul"	Discovery and management of the effects of corrosion of the internal surfaces of the AFW pump turbines. (Group 5)
New	ARDI Program	• Discovery and management of the effects of cavitation erosion of the internal surfaces of AFW piping, down stream of flow orifices 1/2 FO 4506, 4507, and 4540. (Group 1) • Discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the internal surfaces of AFW System components exposed to the AFW fluid. (Group 2) • Discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the external surfaces of AFW components that are not readily accessible and are located in the No. 12 CST enclosure or valve pit. (Group 3) • Discovery and management of the effects of corrosion for the internals of the governor valves and control (i.e., turbine throttle/stop) valves. (Group 5) • Discovery and management of the effects of elastomer degradation and wear seating surfaces on solenoid-operated valves. (Group 7)
New	AFW Buried Pipe Inspection Program	Discovery and management of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting for the external surfaces of buried pipe. (Group 4)
New	Caulking and Sealant Inspection Program	Discovery and management of the effects of elastomer degradation of the perimeter seal of the No. 12 CST. (Group 9)

References

1. "CCNPP Updated Final Safety Analysis Report," Revision 20
2. "CCNPP Aging Management Review Report Auxiliary Feedwater System," Revision 1
3. CCNPP Drawing No. 60583, "Auxiliary Feedwater System," Revision 46, December 10, 1996
4. CCNPP Drawing No. 62583, "Auxiliary Feedwater System," Revision 45, April 20, 1995
5. Letter from Mr. J. C. Linville (NRC) to Mr. G. C. Creel (BGE), dated April 19, 1991, "NRC Region I Combined Inspection Report Nos. 50-317/91-06 and 50-318/91-06," (February 17, 1991 - March 30, 1991)
6. "CCNPP Component Level Scoping Results Report for the Auxiliary Feedwater System," Revision 2
7. "CCNPP Pre-Evaluation Results for the Auxiliary Feedwater System," Revision 1, April 3, 1996
8. "CCNPP Fire Protection Aging Management Review Report," Revision 1, January 29, 1997
9. CCNPP Technical Procedure CP-0217, "Specifications and Surveillance: Secondary Chemistry," Revision 5, December 18, 1995
10. CCNPP Administrative Procedure CH-1, "Chemistry Program," Revision 1, December 13, 1995
11. ANSI N45.2.1, "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants," February 26, 1973
12. Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," March 16, 1973
13. INPO 88-021, "Guidelines for Chemistry at Nuclear Power Stations," Revision 1, September 1991
14. INPO 85-021, "Control of Chemicals in Nuclear Power Plants," June 1985
15. EPRI NP-6239, 5405-2, "PWR Secondary Water Chemistry Guidelines," Final Report, Revision 2, December 1988
16. EPRI TR-102134, Projects 2493, 5401, "PWR Secondary Water Chemistry Guidelines," Final Report, Revision 3, May 1993
17. CCNPP Procedure CP-410, "Make-Up Demineralized Water System"
18. EPRI NP-6377-SL, Volume 2, "Guidelines for the Design and Operation of Make-up Water Treatment Systems, Final Report," June 1989
19. EPRI NP-7077-SR, "Primary Water Chemistry Guidelines," Revision 2, November 1990
20. "NSSS Combustion Engineering Chemistry Manual CENPD-28," Revision 3, September 1982
21. State Water Appropriation Permit#CA69G010
22. CCNPP Technical Procedure CP-202, "Specification and Surveillance - Demineralized Water, Safety-Related Battery Water, Well Water Systems, and Acceptance Criteria for On-Line Monitors," Revision 5, June 19, 1997

23. CCNPP Plant Evaluation Guideline PEG-7, "Plant Engineering Section, System Walkdowns," Revision 4, November 30, 1995

24. INPO 85-032, “Preventive Maintenance,” December 1988

25. INPO 85-037, “Reliable Power Station Operation,” October 1985

26. INPO Good Practice MA-319, “Preventive Maintenance Program Enhancement,” December 1992

27. CCNPP Administrative Procedure MN-1-102, “Preventive Maintenance Program,” Revision 5, September 27, 1996

28. CCNPP Repetitive Tasks 10362000, 10362001, 20362018, And 20362019, "Overhaul AFW Pump Turbine and Governor Valves"

29. CCNPP Technical Procedure TURB-01, "Auxiliary Feedwater Pump Turbine Overhaul,” Revision 2, 10 March, 1997"

30. Letter from Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated March 10, 1989, “Response to Generic Letter 88-14, Instrument Air Supply Problems Affecting Safety-Related Equipment”

31. International Society for Measurement and Control Standard ISA-S7.3-1975 (R 1981), “Quality Standard for Instrument Air,” November 16, 1981

32. CCNPP Operations Performance Evaluation Requirement Nos. 1-12-3-O-M and 2-12-3-O-M, “Run Saltwater Air Compressors,” Revision 2, February 4, 1997

33. CCNPP Drawing No. 60712SH0001, “Compressed Air System, Instrument Air and Plant Air,” Revision 46, December 5, 1996

34. CCNPP Drawing No. 60712SH0003, “Compressed Air System, Instrument Air and Plant Air,” Revision 75, August 2, 1996

35. CCNPP Drawing No. 62712SH0001, “Compressed Air System, Instrument Air and Plant Air,” Revision 37, July 24, 1996

36. CCNPP Drawing No. 62712SH0003, “Compressed Air System, Instrument Air and Plant Air,” Revision 80, February 19, 1997

37. Repetitive Tasks 10191024 and 20191022, “Check Instrument Air Quality at System Low Points,” Preventative Maintenance Program

38. INPO SOER 88-01, “Instrument Air System Failures,” May 18, 1988

5.2 Chemical and Volume Control System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Chemical and Volume Control System (CVCS). The CVCS was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire LRA.

5.2.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools that capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to Aging Management Review (AMR) begins with a listing of passive intended functions and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.2.1.1 presents the results of the system level scoping, 5.2.1.2 the results of the component level scoping, and 5.2.1.3 the results of scoping to determine components subject to an AMR.

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

5.2.1.1 System Level Scoping

This section begins with a description of the system that includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description/Conceptual Boundaries

The purpose of the CVCS is to perform the following functions: [Reference 1, Section 1.1.1; Reference 2, Section 9.1.1]

- Maintain reactor coolant activity at the desired level by removing corrosion and fission products;
- Inject chemicals into the Reactor Coolant System (RCS) to control coolant chemistry and minimize corrosion;
- Control the reactor coolant volume by compensating for coolant contraction or expansion from changes in reactor coolant temperature and other coolant losses or additions;
- Provide means for transferring fluids to the Radioactive Waste Processing System;
- Inject concentrated boric acid into the RCS upon a safety injection actuation signal;
- Control the reactor coolant boric acid concentration;

- Provide auxiliary pressurizer spray for operator control of RCS pressure during startup and shutdown;
- Provide continuous on-line trending of reactor coolant boron concentration and fission product activity; and
- Provide a means for degasifying the RCS prior to maintenance outages and during normal operations.

The CVCS automatically adjusts the volume of water in the RCS using a signal from level instrumentation located on the pressurizer. The system reduces the amount of fluid that must be transferred between the RCS and the CVCS during power changes by employing a programmed pressurizer level setpoint that varies with reactor power level. The CVCS also purifies and conditions the coolant by means of ion exchangers, filters, degasification, and chemical additives. [Reference 2, Sections 9.1.2.2 and 9.1.2.3]

The CVCS is composed of two subsystems: letdown and charging, and makeup. The letdown and charging subsystems' major components are: [Reference 3, Table 1, Page 15 of 47]

- letdown stop valves;
- regeneration heat exchanger;
- excess flow check valves;
- letdown flow control valves;
- letdown heat exchanger;
- letdown backpressure control valves;
- purification filters;
- ion exchangers;
- volume control tank;
- charging pumps;
- boronometer;
- process radiation monitor; and
- reactor coolant pump bleed off containment isolation valves (to the volume control tank).

The makeup subsystem's major components are: [Reference 3, Table 1, Page 15 of 47]

- boric acid batching tank;
- boric acid storage tanks;
- boric acid pumps;
- reactor coolant makeup pumps;
- chemical addition tank;

- chemical addition metering tank; and
- chemical addition metering pump.

Figures 5.2-1 and 5.2-2 are simplified diagrams of the CVCS and are provided for information only. These figures show the portion of the system within the scope of license renewal. [Reference 4, Table 2; References 5 through 10]

Calvert Cliffs' operating experience relative to age-related degradation of CVCS components has included occurrences of charging pump block cracking. Charging pump block cracking in reciprocating pumps is also a recognized industry problem with multiple incidents occurring industry-wide. The cracks are a result of high-cycle mechanical fatigue caused by normal pump operation. The frequency of occurrences of block cracking at CCNPP and other utilities has prompted CCNPP design improvements to the CVCS. In addition, CCNPP operating practices have been modified to run one charging pump during normal operation (rather than two). This change will help extend pump life. [Reference 1, Attachment 6 for Group ID 041-PUMP-02, Page 4]

System Interfaces

The CVCS interfaces with the following systems: [Reference 1, Section 1.1.2; References 5 through 10]

- RCS;
- Nitrogen and Hydrogen System;
- Waste Gas System;
- Reactor Coolant Waste Processing System;
- Compressed Air System;
- Safety Injection System;
- Containment Spray System;
- Spent Fuel Pool Cooling System;
- Process Radiation Monitoring System;
- Component Cooling (CC) System;
- Demineralized Water and Condensate System; and
- Engineered Safety Features Actuation System.

Interfaces in the major flow path of the CVCS are indicated on Figures 5.2-1 and 5.2-2.

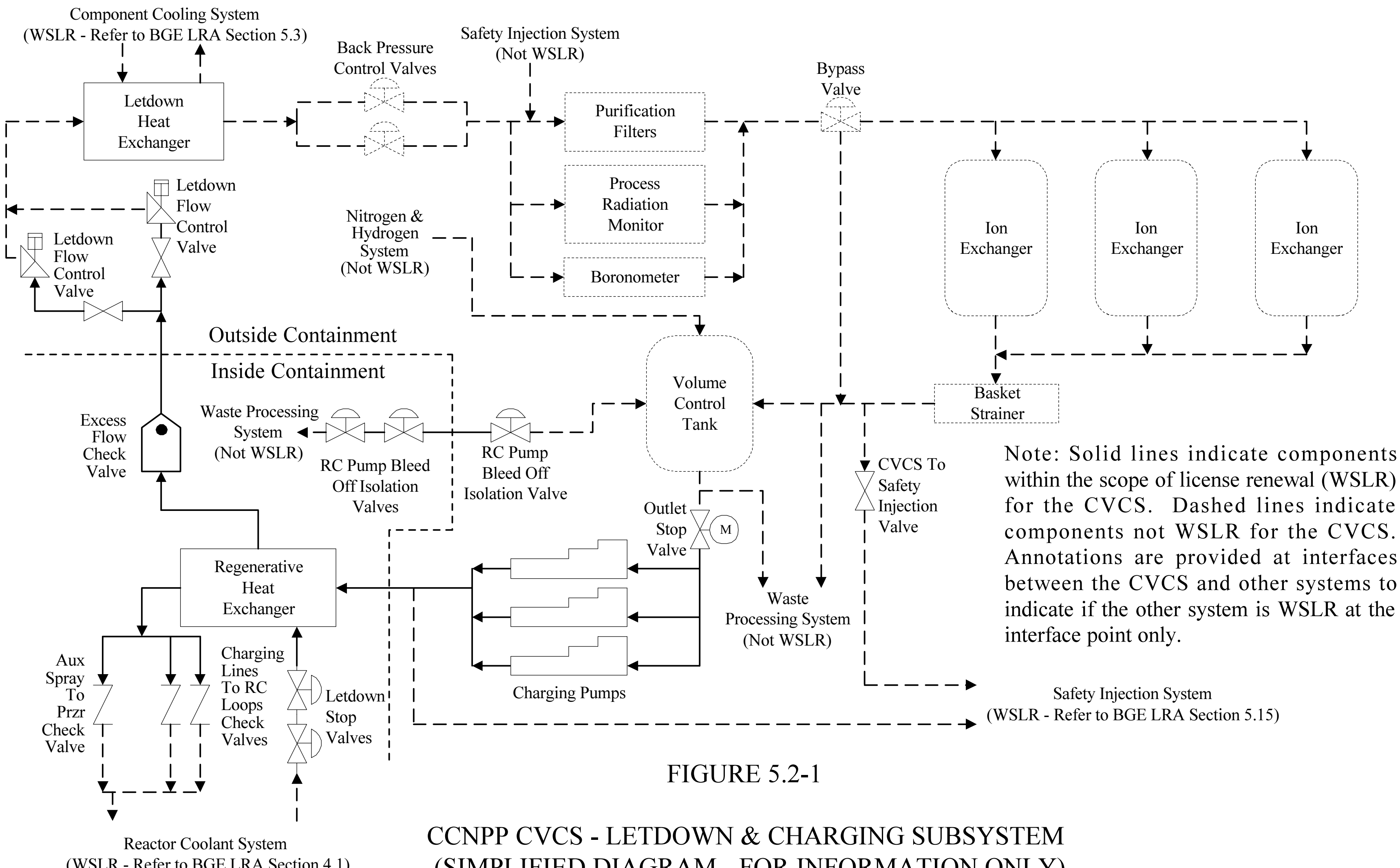


FIGURE 5.2-1

CCNPP CVCS - LETDOWN & CHARGING SUBSYSTEM
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

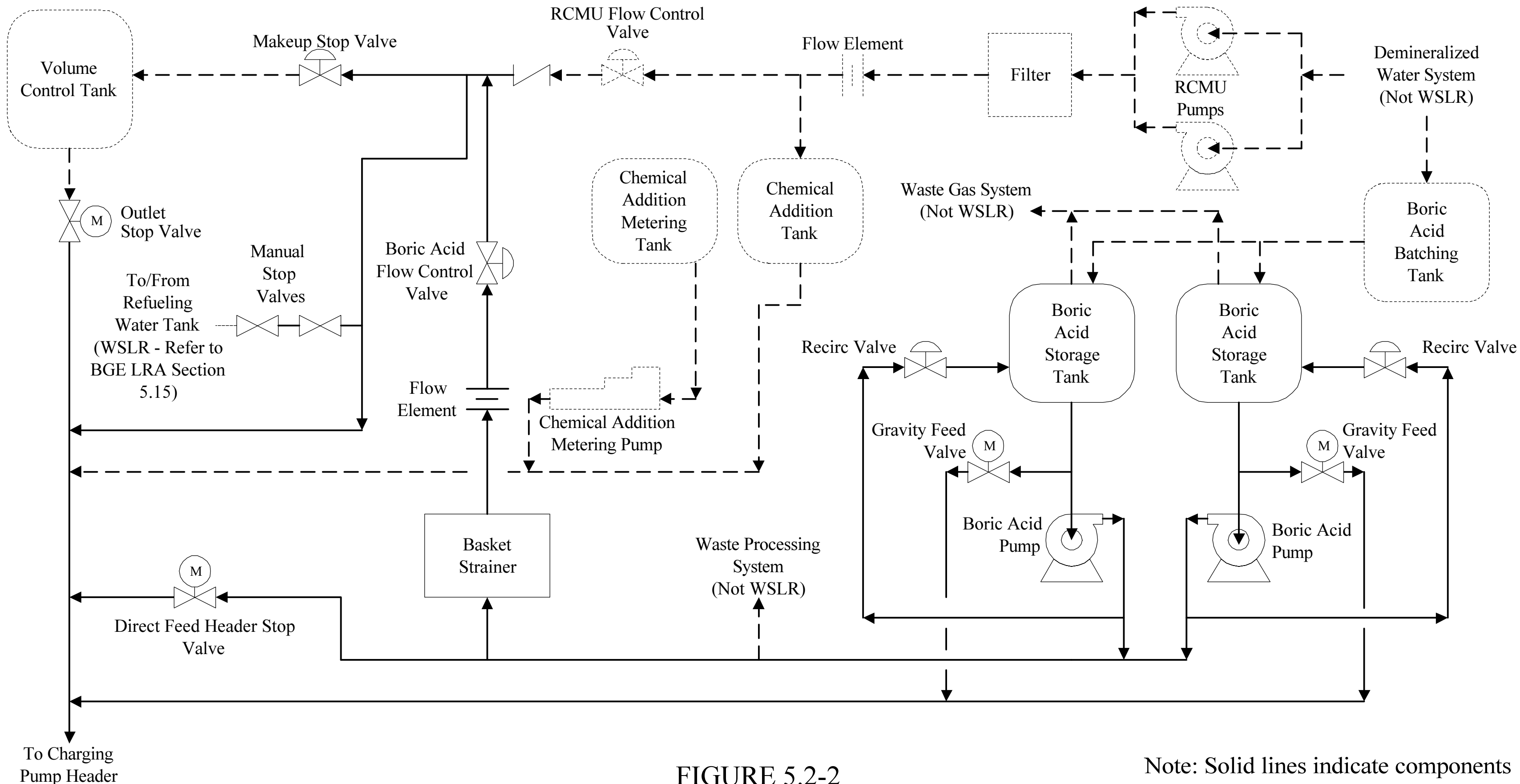


FIGURE 5.2-2

CCNPP CVCS - MAKEUP SUBSYSTEM
(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

Note: Solid lines indicate components WSLR for the CVCS. Dashed lines indicate components not WSLR for the CVCS. Annotations are provided at interfaces between the CVCS and other systems to indicate if the other system is WSLR at the interface point only.

System Scoping Results

The CVCS is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the CVCS were determined based on the requirements of §54.4(a)(1) and (2) in accordance with the CCNPP IPA Methodology Section 4.1.1: [Reference 1, Section 1.1.3; Reference 4, Table 1]

- To provide containment isolation of the CVCS during a loss-of-coolant accident (LOCA); Note - This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3).
- To inject concentrated boric acid into the RCS for reactivity control and RCS pressure and level control during design basis events; Note - This function also applies to pressurized thermal shock (10 CFR 50.61) and fire protection (10 CFR 50.48) based on §54.4(a)(3).
- To provide radiological release control by isolating the RCS letdown line during a LOCA;
- To maintain the pressure boundary of the CVCS (liquid and/or gas);
- To provide long-term core flush via pressurizer auxiliary spray; Note - This function also applies to pressurized thermal shock (10 CFR 50.61) based on §54.4(a)(3).
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain mechanical operability and/or provide protection of the mechanical system;
- To restrict flow to a specified value in support of a design basis event response; and
- To provide seismic integrity and/or protection for safety-related components.

The following intended functions of the CVCS were determined based on the requirements of §54.4(a)(3): [Reference 4, Table 1]

- For post-accident monitoring - To provide information used to assess the environs and plant condition during and following an accident;
- For fire protection (10 CFR 50.48) - To provide RCS pressure and inventory control to ensure safe shutdown in the event of a postulated severe fire; and
- For environmental qualification (10 CFR 50.49) - To maintain functionality of electrical components as addressed by the Environmental Qualification Program.

5.2.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the CVCS that is within the scope of license renewal includes all components (electrical, mechanical, and instrumentation) and their supports along the following system flowpaths, as indicated on Figures 5.2-1 and 5.2-2: [Reference 4, Table 2; References 5 through 10]

- From the RCS interface at the letdown stop valves through the regenerative heat exchanger to the letdown flow control valves. The letdown heat exchanger is also within the scope of license renewal due to its safety-related pressure boundary for the CC System, although the piping between the letdown flow control valves and the letdown heat exchanger is not within the scope of license renewal;
- From the volume control tank outlet stop valve through the charging pumps and regenerative heat exchanger to the auxiliary spray and charging line check valves;

- From the reactor coolant pump bleed off isolation valves inside containment through the containment penetration to the isolation valve outside containment;
- From the boric acid storage tanks through the boric acid pumps to the charging pumps header and to the makeup stop valve; and
- From the boric acid storage tanks through the gravity feed valves to the charging pumps header.

All piping within the scope of license renewal for the CVCS is identified as being within the safety-related pressure boundary as shown on the system piping and instrumentation diagrams. The piping and instrumentation diagrams also denote that all equipment within this boundary are considered safety-related pressure boundary components. Calvert Cliffs' components designated as safety-related pressure boundary are designed as Seismic Category 1 and are subject to the applicable loading conditions identified in UFSAR Section 5A.3.2 for Seismic Category 1 systems and equipment design. [References 5 through 11]

A total of 53 device types within the CVCS were designated as within the scope of license renewal because they have at least one intended function. These device types are listed in Table 5.2-1. [Reference 1, Table 2.1; References 12 and 13]

TABLE 5.2-1

CVCS DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Code	Device Description
#CC	Stainless Steel Piping (1500 psig rating)
#HC	Stainless Steel Piping (150 psig rating)
ACC	Accumulator
BS	Basket Strainer
CKV	Check Valve
COIL	Coil
CS	Control Switch
CV	Control Valve
CVOP	Control Valve Operator
DISC	Disconnect Switch/Link
FE	Flow Element
FIA	Flow Indicator Alarm
FO	Flow Orifice
FT	Flow Transmitter
FU	Fuse
FY	Flow Device (Relay)
HIC	Hand Indicator Controller
HS	Handswitch
HV	Hand Valve
HX	Heat Exchanger
I/P	Current/Pneumatic Device
II	Ammeter
JL	Power Lamp Indicator
LC	Level Controller
LIA	Level Indicator Alarm
LIT	Level Indicating Transmitter
LS	Level Switch
LY	Level Device (Relay)
M	480V Motor (Feed from Motor Control Center)
MB	480V Motor
MD	125/250VDC Motor
MOV	Motor Operated Valve
MOVOP	Motor Operated Valve Operator
PC	Pressure Controller
PCV	Pressure Control Valve
PDI	Pressure Differential Indicator
PI	Pressure Indicator
PNL	Panel
PS	Pressure Switch

TABLE 5.2-1 (continued)

CVCS DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Code	Device Description
PT	Pressure Transmitter
PUMP	Pump/Driver Assembly
QHT	Heat Tracing Controller
RV	Relief Valve
RY	Relay
SV	Solenoid Valve
TE	Temperature Element
TIC	Temperature Indicating Controller
TK	Tank
TS	Temperature Switch
U	Heater
XL	Miscellaneous Indicating Lamp
ZL	Position Indicating Lamp
ZS	Position Switch

In addition, some components within the scope of license renewal are common to many plant systems and perform the same passive functions regardless of system. These components are not included in the above table and are as follows:

- Structural supports for piping, cables, and components;
- Electrical cabling; and
- Instrument lines (i.e., tubing and small bore piping), tubing supports, instrument valves (e.g., equalization, vent, drain, isolation), and fittings.

5.2.1.3 Components Subject to AMR

This section describes the components within the CVCS that are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following CVCS functions were determined to be passive: [Reference 1, Table 3-1; Reference 14, Attachment 1]

- To provide containment isolation of the CVCS during a LOCA;
- To maintain the pressure boundary of the CVCS (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system;
- To restrict flow to a specified value in support of a design basis events response; and
- To provide seismic integrity and/or protection for safety-related components.

Device Types Subject to AMR

Of the 53 device types within the scope of license renewal for the CVCS shown in Table 5.2-1:

- Twenty-eight device types have only active functions. These device types are: COIL, CS, CVOP, DISC, FIA, FU, FY, HIC, HS, I/P, II, JL, LC, LIT, LY, M, MB, MD, MOVOP, PC, QHT, RY, TIC, TS, U, XL, ZL, and ZS. [Reference 1, Table 2-1, Table 3-2]
- None of the device types are subject to periodic replacement. [Reference 1, Table 3-2; Reference 14, Attachment 2]
- Eight device types are evaluated in commodity AMRs. Device types FT, LIA, LS, PDI, PI, PS, and PT are evaluated in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA, and device type PNL is evaluated in the Electrical Panels Commodity Evaluation in Section 6.2 of the BGE LRA. Note - Some HVs and some CKVs are evaluated in the Instrument Lines Commodity Evaluation and the remaining HVs and CKVs are included in this report. [Reference 1, Table 3-2; Reference 14, Attachments 3, 4, 4A]

Of the 53 device types within the scope of license renewal for the CVCS, the remaining 17 device types, listed in Table 5.2-2, are subject to AMR and are included in the scope of this report. [Reference 1, Table 3-2; References 12 and 13]

Some components in the CVCS are common to many plant systems and perform the same passive function regardless of system (i.e., structural supports, electrical cabling, and instrument lines as discussed in Section 5.2.1.2 above). Therefore, these components are not included in the 53 CVCS device types discussed above, and they were evaluated as follows:

- Structural supports for piping, cables and components in the CVCS that are subject to AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. This commodity evaluation, in conjunction with the Electrical Panels Commodity Evaluation discussed above, completely addresses the CVCS passive intended function, “To provide seismic integrity and/or protection of safety-related components.”
- Electrical cabling for components in the CVCS that are subject to AMR are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the CVCS passive intended function, “To maintain electrical continuity and/or provide protection of the electrical system.”
- Instrument lines (i.e., tubing and small bore piping), tubing supports, instrument valves (e.g., equalization, vent, drain, isolation), and fittings for components in the CVCS that are subject to AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. This commodity evaluation addresses the CVCS passive intended function, “To maintain the pressure boundary of the CVCS (liquid and/or gas)” for instrument lines, and the associated supports, instrument valves, and fittings.

The only passive intended functions associated with the CVCS that are not completely addressed by one of the commodity evaluations discussed above are as follows:

- To provide containment isolation of the CVCS during a LOCA;
- To maintain the pressure boundary of the CVCS (liquid and/or gas); and

- To restrict flow to a specified value in support of a design basis event response.

Therefore, only the 3 functions listed above for the 17 device types listed in Table 5.2-2 are addressed by the remainder of this report.

TABLE 5.2-2

CVCS DEVICE TYPES REQUIRING AMR

Device Code	Device Description
#CC	Stainless Steel Piping (1500 psig rating)
#HC	Stainless Steel Piping (150 psig rating)
ACC	Accumulator
BS	Basket Strainer
CKV	Check Valve
CV	Control Valve
FE	Flow Element
FO	Flow Orifice
HV	Hand Valve
HX	Heat Exchanger
MOV	Motor Operated Valve
PCV	Pressure Control Valve
PUMP	Pump/Driver Assembly
RV	Relief Valve
SV	Solenoid Valve
TE	Temperature Element
TK	Tank

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on a qualified life or specified time period would not be subject to AMR.

5.2.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the CVCS components is given in Table 5.2-3, with plausible ARDMs identified by a check mark (✓) in the appropriate device type column. [Reference 1, Attachment 1, Attachment 5s] A check mark indicates that the ARDM applies to at least one component for the device type listed.

For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. Table 5.2-3 also identifies the group to which each ARDM/device type combination belongs. The following groups have been selected for the CVCS:

Group 1 - Includes the device types subject to thermal fatigue.

Group 2 - Includes the device types with borated water or boric acid internal environments subject to crevice corrosion, general corrosion, and pitting.

Group 3 - Includes the device types with air internal environments subject to general corrosion.

Group 4 - Includes shell side of heat exchangers (i.e., cooling water internal environment) subject to crevice corrosion and pitting.

Group 5 - Includes the device types subject to wear.

Group 6 - Includes the device types subject to vibrational fatigue.

Group 7 - Includes the device types subject to stress corrosion cracking.

TABLE 5.2-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE CVCS

Potential ARDMs	Device Types																		
	#CC	#HC	ACC	BS	CKV	CV Air	CV Water	FE	FO	HV	HX	MOV	PCV	PUMP	RV	SV	TE	TK	Not Plausible for System
Cavitation Erosion																			x
Corrosion Fatigue																			x
Crevice Corrosion		✓ (2)			✓ (2)					✓ (2)	✓ (4)	✓ (2)							
Dynamic Loading																			x
Erosion Corrosion																			x
Fatigue (thermal or vibrational)	✓ (1)	✓ (6)			✓ (1)		✓ (1)			✓ (1, 6)	✓ (1)			✓ (6)	✓ (6)		✓ (1)		
Fouling																			x
Galvanic Corrosion																			x
General Corrosion	✓ (2)	✓ (2)		✓ (2)	✓ (2)	✓ (3)	✓ (2)			✓ (2)	✓ (2)	✓ (2)	✓ (3)	✓ (2)	✓ (2)			✓ (2)	
Hydrogen Damage																			x
Intergranular Attack																			x
MIC																			x
Particulate Wear Erosion																			x
Pitting		✓ (2)			✓ (2)					✓ (2)	✓ (4)	✓ (2)							
Radiation Damage																			x
Rubber Degradation																			x
Saline Water Attack																			x
Selective Leaching																			x
Stress Corrosion Cracking		✓ (7)			✓ (7)		✓ (7)	✓ (7)		✓ (7)		✓ (7)			✓ (7)				
Thermal Damage																			x
Thermal Embrittlement																			x
Wear					✓ (5)		✓ (5)												

✓ - indicates plausible ARDM determination
(#) - indicates the group(s) in which this ARDM/device type combination is evaluated
MIC = Microbiologically-Induced Corrosion

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods to managing aging, aging management program(s), and aging management demonstration.

Group 1 (Device types subject to thermal fatigue) - Materials and Environment

As shown in Table 5.2-3, Group 1 applies to device types #CC, CKV, CV (Water), HV, HX, and TE that are subject to fatigue.

Group 1 consists of the following CVCS components: piping, control valves, and hand valves in the RCS letdown line to the tube side of the Regenerative Heat Exchanger, the Regenerative Heat Exchanger, the Regenerative Heat Exchanger discharge temperature element, the Letdown Heat Exchanger, and the check valves at the CVCS/RCS interface downstream of the Regenerative Heat Exchanger. [Reference 1, Attachment 1, Attachment 3s for Group IDs #CC-02, CKV-09, CKV-14, CV-04, HV-08; HX-01, HX-02, TE-02; Reference 6]

All of the Group 1 components have the passive intended function to maintain pressure boundary integrity. The Group 1 control valves also have a containment isolation passive intended function. [Reference 1, Attachment 1]

Fatigue is plausible for the following subcomponent parts: [Reference 1, Attachment 1]

- #CC - pipe, fittings, flanges, studs, nuts, and welds;
- CKV - body and bonnet;
- CV - body/bonnet, stem, studs, nuts, plug, and bushing;
- HV - body/bonnet, stem, studs, nuts, and disc and seat;
- HX - tubes/tubesheet, studs and nuts (for Letdown Heat Exchanger), channel/cover (for Letdown Heat Exchanger), channel and welds (for Regenerative Heat Exchanger); and
- TE - element.

The subcomponent parts for the Group 1 components that come in contact with the CVCS process fluid are primarily constructed of stainless steel. The Group 1 subcomponent parts external to the process stream (e.g., studs and nuts) are constructed of alloy steel, carbon steel, or stainless steel. [Reference 1, Attachment 4s]

The internal environment for the Group 1 CVCS components is borated water. Loss of Letdown or Loss of Charging Flow transients can result in rapid increases or decreases in CVCS fluid temperature. These transients can result in rapid temperature transitions between 120°F and 550°F (i.e., differential temperature of up to 430°F). [Reference 1, Attachment 3s , Attachment 6s; Reference 15, Attachment 5; Reference 16, Section 4.4.2]

Group 1 (Device types subject to thermal fatigue) - Aging Mechanism Effects

Fatigue is the process of progressive localized structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points in the material. This process may culminate in cracks or complete fracture after a sufficient number of fluctuations. The fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure occurs. Failures may occur at either a high or low number of cycles in response to various kinds of loads (e.g., mechanical or vibrational loads, thermal cycles, or pressure cycles). Low-cycle fatigue involves stressing of materials, often into the plastic range, with the number of cycles usually being less than 10^5. This mechanism is typically associated with thermal gradients created in thick sections (e.g., > 1") or in restrained members during rapid heatup or cooldown. [Reference 1, Attachment 7s; Reference 17, Pages 14, 66]

Low-cycle thermal fatigue is plausible since frequent CVCS operation may produce a large number of thermal transients, with an additional number of these stress cycles expected during the period of extended operation. [Reference 1, Attachment 6s]

This aging mechanism, if unmanaged, could eventually result in crack initiation and growth such that the Group 1 components may not be able to perform their pressure boundary and containment isolation functions under current licensing basis (CLB) conditions. Therefore, thermal fatigue was determined to be a plausible ARDM for which the aging effects must be managed for the Group 1 components.

Group 1 (Device types subject to thermal fatigue) - Methods to Manage Aging

Mitigation: The effects of thermal fatigue can be mitigated by reducing the number and severity of the thermal transients experienced by the system and by proper system design and material selection.

Discovery: The effects of thermal fatigue can be managed by monitoring the total fatigue damage accumulated by critical CVCS components as a result of all stress cycles that the components have experienced during their service lives. The accumulation of fatigue effects can be monitored by counting the number of the thermal transients and by performing analysis to predict the remaining life of the affected components.

Group 1 (Device types subject to thermal fatigue) - Aging Management Program(s)

Mitigation: As discussed above, the effects of thermal fatigue can be mitigated by reducing the number and severity of the thermal transients experienced by the system. As a part of general operating practice, plant operators minimize the length and severity of transitory operational cycles.

Discovery: The CCNPP Fatigue Monitoring Program (FMP) is based on Reference 16 and has been established to monitor and track fatigue usage of limiting components of the Nuclear Steam Supply System and the steam generators. Eleven fatigue critical locations in these systems have been selected for monitoring of fatigue usage. These represent the most bounding locations for critical thermal transients. For the CVCS, the Charging Inlet Nozzle has been identified as the most bounding location. [Reference 15, Sections 1,1, 1.2.A, 2.1.E, 6.0; Reference 18]

The FMP utilizes two methods to track fatigue usage. One method is to track the number of critical thermal and pressure test transients (i.e., cycle counting) and compare them to the number allowed in the piping design analysis. The piping design analysis is performed assuming a particular number and severity of various transients. In accordance with either American Society of Mechanical Engineers (ASME) Section III or American National Standards Institute (ANSI) B31.7, the analysis demonstrates that the component has an acceptable design as long as the assumptions remain valid. Therefore, if the actual number and severity of transients experienced by the component remains below the number assumed in the analysis, then the component remains within its design basis.

The other method is to determine the fatigue life of a component using a calculated cumulative usage factor (CUF), which is defined as a normalized measure of total fatigue damage accumulated by a component as a result of all stress cycles that the component has experienced during its service life. The FMP monitors actual fatigue usage. The CUF can be calculated and tracked through plant life using thermal cycle counting or stress-based analysis techniques. Both methods use actual plant operating data. The usage factor for several locations, including the Charging Inlet Nozzle, is calculated through stress-based analysis, which is the more rigorous method, and which provides a more realistic CUF. In accordance with the code, the component remains within its design basis for allowable fatigue life if the CUF remains less than or equal to 1.0. [Reference 15, Sections 1.2.A, 3.0.B, 3.0.F; Reference 18]

The data for thermal transients is collected, recorded, and analyzed using software that evaluates input data from plant instrumentation. The software is used to analyze plant data associated with real transients and to predict the number of thermal cycle transients for 40 and 60 years of plant operation based on the historical records. For the CVCS, the allowable number of Loss of Charging cycles is 1400, and the allowable number of Loss of Letdown cycles is 50. The present analysis for the Loss of Letdown transient predicts that Unit 1 will experience 79 cycles for 40 years of plant operation and 118 cycles for 60 years, and that Unit 2 will experience 40 cycles for 40 years and 61 cycles for 60 years. Since some of the predicted values exceed the allowable number of 50 cycles for this transient, analysis is being performed to justify increasing the number of design allowable cycles. [Reference 15, Section 3.0.F; Reference 18]

Plant parameter data is collected on a periodic basis and reviewed to ensure that the data represents actual transients. Valid data is entered into the software, which counts the critical transient cycles and calculates the CUFs. The transient data is evaluated and the CUFs are calculated on a semi-annual basis, which provides a readily predictable approach to the alert value. The data is tracked in accordance with procedures that are governed by a quality assurance program that meets 10 CFR Part 50, Appendix B, criteria. A CUF of less than 1.0, and/or the number of cycles remaining below the design allowable number, are acceptable conditions for any given component since no crack initiation would be predicted. In order to stay within the design basis, corrective action is initiated well in advance of the CUF approaching 1.0 or the number of cycles approaching the design allowable, so that appropriate corrective actions can be taken in a timely and coordinated manner. [Reference 15, Sections 1.2.A, 5.0]

The CCNPP FMP has been inspected by the NRC, which noted that the program has been developed toward providing assurance that fatigue life usage of primary system components has not exceeded limits provided for in the ASME Boiler and Pressure Vessel Code for Nuclear Vessels - Section III. In addition, the NRC noted that the FMP can be used to identify components where fatigue usage may challenge the remaining and extended life of the components, and can provide a basis for corrective action where necessary. [Reference 19]

Since the FMP has been initiated, no locations have reached the limit on fatigue usage and no cracking due to low-cycle fatigue has been discovered. The FMP has undergone several modifications since its inception. Stress based analysis was added to the software to calculate the CUFs for several locations due to unique thermal transients experienced and the unique geometries involved. Other modifications have been made to the FMP to reflect plant operating conditions more accurately. The plant design change process has also been modified to require notification to the Life Cycle Management Unit of any proposed changes to the critical locations being monitored.

To fully address fatigue for license renewal, CCNPP participated in an Electric Power Research Institute (EPRI) sponsored task to demonstrate the industry fatigue position. The task applied industry-developed methodologies to identify fatigue sensitive component locations that may require further evaluation or inspection for license renewal and evaluate environmental effects as necessary. The program objective included the development and justification of aging management practices for fatigue at various component locations for the renewal period. The demonstration systems were the Feedwater System, the pressurizer surge line, and the Charging/Letdown System. [Reference 20, Page 3]

Generic Safety Issue 166

Generic Safety Issue (GSI) 166, Adequacy of Fatigue Life of Metal Components, identifies concerns identified by the NRC, which must be evaluated as part of the license renewal process. The NRC staff concerns about fatigue for license renewal fall into five categories: [Reference 20, Page 2; Reference 21]

- The first category is the adequacy of the fatigue design basis when environmental effects are considered. This concern has been addressed by the EPRI sponsored Charging/Letdown fatigue task described above.
- The second category is the adequacy of both the number and severity of design basis transients. This concern has been addressed by the EPRI sponsored Charging/Letdown fatigue task described above.
- The third category is the adequacy of inservice inspection requirements and procedures to detect fatigue indications. This concern does not apply to the CVCS because the CCNPP Inservice Inspection Program is not credited with managing fatigue for CVCS components.
- The fourth category is the adequacy of the fatigue design basis for Class I piping components designed in accordance with ANSI B31.1. This concern does not apply to the CVCS because the CVCS piping subject to fatigue is designed in accordance with ANSI B31.7, Class II requirements.
- The fifth category is the adequacy of actions to be taken when the fatigue design basis is potentially compromised. This concern is adequately addressed by the CCNPP FMP as discussed above.

Group 1 (Device types subject to thermal fatigue) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 1 components subject to thermal fatigue:

- The Group 1 components have the passive intended functions to maintain pressure boundary integrity and to provide containment isolation under CLB conditions.

- Thermal fatigue is plausible for the Group 1 components which, if unmanaged, could eventually result in crack initiation and growth such that the components may not be able to perform their pressure boundary and containment isolation functions under CLB conditions.
- The CCNPP FMP monitors the fatigue usage at bounding locations to ensure that the Group 1 components remain within their design basis and includes acceptance criteria to ensure timely corrective action is taken prior to degradation that would compromise the pressure boundary and containment isolation functions.

Therefore, there is reasonable assurance that the effects of thermal fatigue will be managed for the Group 1 components such that they will be capable of performing their pressure boundary and containment isolation functions, consistent with the CLB, during the period of extended operation.

Group 2 (Device types with borated water or boric acid internal environments subject to crevice corrosion, general corrosion, and pitting) - Materials and Environment

As shown in Table 5.2-3, Group 2 applies to device types #HC, CKV, HV, and MOV that are subject to crevice corrosion, general corrosion, and pitting; and device types #CC, BS, CV (Water), HX, PUMP, RV, and TK that are subject to general corrosion. Group 2 consists of miscellaneous CVCS components with borated water or boric acid internal environments. [Reference 1, Attachment 1, Attachment 3s for Group IDs #CC-02, #CC-03, #CC-04, #CC-05, #HC-01, #HC-02, #HC-03, #HC-05, #HC-06, BS-01, CKV-02, CKV-04, CKV-05, CKV-08, CKV-10, CKV-11, CKV-14, CV-01, CV-02, CV-05, CV-09, HV-01, HV-02, HV-06, HV-07, HV-08, HV-11, HV-12, HV-13, HV-14, HV-15, HV-16, HX-01, HX-02, MOV-01, MOV-02, MOV-03, MOV-04, PUMP-01, PUMP-02, RV-06, TK-01]

Nearly all of the Group 2 components have the passive intended function to maintain pressure boundary integrity. Some of the Group 2 control valves and check valves have the containment isolation passive intended function. [Reference 1, Attachment 1]

Crevice corrosion and pitting are plausible for portions of the system that do not have hydrogen overpressure and do not have frequent circulation (i.e., flow is stagnant). Crevice corrosion and/or pitting are plausible for the following subcomponent parts: [Reference 1, Attachment 1]

- #HC - pipe (for some #HCs), fittings (for some #HCs), welds (for some #HCs), studs (for some #HCs), nuts (for some #HCs), and flanges (for some #HCs);
- CKV - studs (for some CKVs), nuts (for some CKVs), and body/bonnet (for some CKVs);
- HV - body/bonnet (for some HVs), stem (for some HVs), studs (for some HVs), nuts (for some HVs), disc (for some HVs), seat (for some HVs), and gland flange (for some HVs); and
- MOV - body/bonnet (for some MOVs), stem (for some MOVs), studs (for some MOVs), and nuts (for some MOVs).

General corrosion is plausible for the following subcomponent parts: [Reference 1, Attachment 1]

- #CC - studs and nuts;
- #HC - studs and nuts;
- BS - studs and nuts;

- CKV - studs (for some CKVs), and nuts (for some CKVs);
- CV (Water) - studs and nuts;
- HV - studs (for some HVs), nuts (for some HVs), and packing flange (for some HVs);
- HX - cradles, shell (for some HXs), studs (for some HXs), nuts (for some HXs), and welds (for some HXs);
- MOV - studs and nuts;
- PUMP - bolts;
- RV - studs and nuts; and
- TK - studs and nuts.

The subcomponent parts for the Group 2 components that come in contact with the CVCS process fluid are primarily constructed of stainless steel. The Group 2 subcomponent parts external to the process stream (e.g., studs and nuts) are primarily constructed of alloy steel or carbon steel. [Reference 1, Attachment 4s]

The internal environment for the Group 2 components is borated water or boric acid. Stagnant flow conditions may exist in portions of the system due to the physical geometry of the components, and due to idle operation of portions of the system. Stagnation of the flow may allow impurities in the process fluid to concentrate. [Reference 1, Attachment 3s , Attachment 6s]

Group 2 (Device types with borated water or boric acid internal environments subject to crevice corrosion, general corrosion, and pitting) - Aging Mechanism Effects

Stainless steel and carbon steel are susceptible to crevice corrosion and pitting in a stagnant, fluid environment. The aggressiveness of these corrosion mechanisms are particularly dependent on fluid chemistry conditions and oxygen levels. Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, and other mechanical joints which have a crevice geometry. 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. Crevice corrosion is closely related to pitting corrosion and can initiate pits (i.e., loss of material) in many cases. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. Pitting is a form of localized attack with greater corrosion rates at some locations than at others. This form of corrosion essentially produces holes of varying depth. High concentrations of impurity anions such as chlorides and sulfates tend to concentrate in the pit region, giving rise to a potentially aggressive solution in this zone. Since the Group 2 components can be subject to stagnant fluid conditions that may allow impurities in the process fluid to concentrate, a potentially corrosive environment may exist. Therefore, crevice corrosion and pitting were determined to be plausible for the Group 2 components. [Reference 1, Attachment 6s and 7s]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. This ARDM is plausible for the external surfaces of the Group 2 components because susceptible materials of construction (e.g., alloy steel, carbon steel) are exposed to potential borated water or boric acid leakage from mechanical joints in the CVCS piping system. General corrosion is not plausible for stainless steel. Additionally, crevice corrosion and pitting can occur when crevices (e.g., under nuts and/or bolt heads) are exposed to leakage. [Reference 1, Attachment 6s and 7s]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 2 components may not be able to perform their pressure boundary and containment isolation functions under CLB conditions. Therefore, crevice corrosion, general corrosion, and pitting were determined to be plausible ARDMs for which the aging effects must be managed for the Group 2 components.

Group 2 (Device types with borated water or boric acid internal environments subject to crevice corrosion, general corrosion, and pitting) - Methods to Manage Aging

Mitigation: The effects of crevice corrosion and pitting that occur due to fluid stagnation, can be mitigated by minimizing the exposure of the internal surfaces of the Group 2 components to an aggressive environment. Maintaining system chemistry conditions to minimize impurities will limit the rate and effects of degradation due to these ARDMs. [Reference 1, Attachment 6s, Attachment 8]

The effects of general corrosion, crevice corrosion, and pitting that occur due to leakage of borated water or boric acid leakage, can be mitigated by performing inspections of the external surfaces of the Group 2 components for signs of leakage or boric acid residue and taking appropriate corrective action (e.g., removal of boric acid residue) prior to the onset of corrosion degradation. [Reference 1, Attachment 6s, Attachment 8]

Discovery: The degradation of the Group 2 components that does occur can be discovered and monitored by performing visual inspections of the subcomponent parts subject to crevice corrosion, general corrosion, and pitting. Visual inspections would need to be performed on the internal surfaces of the Group 2 components to detect corrosion associated with fluid stagnation, and on the external surfaces to detect corrosion associated with leakage of borated water or boric acid.

Group 2 (Device types with borated water or boric acid internal environments subject to crevice corrosion, general corrosion, and pitting) - Aging Management Program(s)

Mitigation: Calvert Cliffs Technical Procedure CP-204, "Specification and Surveillance Primary Systems," is the program credited with managing the effects of crevice corrosion and pitting that occur due to fluid stagnation on the internal surfaces of the Group 2 components. The program provides for monitoring and maintaining the RCS and associated systems (including the CVCS) chemistry. The chemistry controls provided by CP-204 have been established to: minimize impurity ingress to plant systems; reduce corrosion product generation, transport, and deposition; reduce collective radiation exposure through chemistry; improve integrity and availability of plant systems; and extend component and plant life. Maintaining system chemistry conditions to minimize impurities limits the rate and effects of component degradation. Calvert Cliffs Technical Procedure CP-204 is based on the Technical Specifications, BGE's interpretation of industry standards, and recommendations made by Combustion Engineering. [Reference 1, Attachment 8; Reference 22, Sections 1.0, 2.0; Reference 23, Section 6.1.A]

The scope of CP-204 includes the following systems/components: [Reference 22, Section 2.0, Attachments 1 through 13]

- Reactor Coolant (Modes 1 through 6);
- Spent Fuel Pool (Modes 1 through 6);
- Refueling Water Storage Tank (Modes 1 through 6);
- Refueling Pool (Mode 6);
- Safety Injection Tanks (Modes 1 through 6);
- High Pressure Safety Injection Pump Discharge (Modes 1 through 6);
- Boric Acid Storage Tank (Modes 1 through 6);
- Reactor Coolant Waste Receiver Tank (Modes 1 through 6);
- Reactor Coolant Waste Evaporator Bottoms (Modes 1 through 6);
- Boric Acid Batching Tank (Modes 1 through 6);
- CVCS Ion Exchangers (Modes 1 through 6); and
- Spent Fuel Pool Ion Exchangers (Modes 1 through 6).

Calvert Cliffs Technical Procedure CP-204 describes the surveillance and specifications for monitoring the primary systems' fluid chemistry. CP-204 lists the parameters to monitor (e.g., chloride, fluoride, sulfate, oxygen, pH), the frequency of monitoring these parameters, and the acceptable value or range of values for each parameter. The primary chemistry parameters are measured at procedurally-specified frequencies (e.g., daily, weekly, monthly), and are compared against "target values" that represent a goal or predetermined warning limit. If a target value is not met, corrective actions are taken as prescribed by the procedure, thereby ensuring timely response to chemical excursions. [Reference 22, Sections 3.0.C.4, 6.0]

The chemistry program at CCNPP (which includes CP-204) is subject to periodic internal assessment. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 24, Section 1B.18]

Operating experience relative to the chemistry program at CCNPP is that it has been effective in its function of minimizing corrosion and corrosion-related failures and problems.

Calvert Cliffs Technical Procedure CP-204 provides for a prompt review of primary system chemistry parameters so that steps can be taken to return chemistry parameters to normal levels and thus minimizing impurities which will limit the rate and effects of degradation due to corrosion mechanisms. [Reference 1, Attachment 8; Reference 22, Section 2.0]

The CCNPP "Boric Acid Corrosion Inspection Program," (MN-3-301) is credited with mitigating the effects of general corrosion on the external surfaces of the Group 2 components through discovery of leakage and removal of any boric acid residue that is found. Removal of any boric acid residue from component external surfaces mitigates the corrosion effects on the Group 2 components prior to the onset of corrosion degradation. Further details on the Boric Acid Corrosion Inspection (BACI) Program are detailed in the Discovery section below. [Reference 25]

Discovery: To verify that no significant crevice corrosion or pitting is occurring on the internal surfaces of the Group 2 components, a new plant program will be developed to provide requirements for inspections of representative components. The program is considered an Age-Related Degradation Inspection (ARDI) Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA).

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of adverse examination findings, including consideration of all design loadings required by the CLB and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

The corrective actions taken as part of the ARDI Program will ensure that the Group 2 components remain capable of performing their passive intended functions under all CLB conditions.

Calvert Cliffs Administrative Procedure MN-3-301 provides systematic requirements to ensure that boric acid corrosion does not degrade the reactor coolant pressure boundary and thereby increase the probability of abnormal leakage, rapidly propagating failure, or rupture. The program establishes programmatic guidelines in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR *[pressurized water reactor]* Plants." [Reference 25, Section 1.1; Reference 26]

The scope of the program is threefold: (1) It provides examination locations where leakage may cause degradation of the primary pressure boundary by boric acid corrosion; (2) It provides examination requirements and methods for the detection of leaks; and (3) It provides the responsibilities for initiating engineering evaluations and the subsequent proposed corrective actions. [Reference 25, Section 1.2]

The program requires a containment walkdown following each reactor shutdown (as soon as possible after attaining Hot Shutdown condition) in order to identify and quantify any leakage found in specific areas of the Containment Building. A second walkdown is performed during heatup prior to plant startup (after attaining normal operating pressure and temperature) if leakage was identified and corrective actions were taken. Only locations where leakage has previously been identified need to be included in this second walkdown. The walkdowns are performed in accordance with CCNPP Administrative Procedure MN-3-

110, "Inservice Inspection of ASME Section XI Components," and procedure MN-3-301. A containment walkdown is not necessary if a reactor shutdown occurs within 30 days of a previous shutdown, unless the reason for the shutdown is excessive RCS leakage. [Reference 25, Section 5.1]

The program also requires examination of specific components for discovery of leakage during each refueling outage. Some of the components examined include carbon steel bolting on Class 1 valves and valves in systems containing borated water that could leak onto Class 1 carbon steel components. [Reference 25, Section 5.1.B]

Leakage or corrosion discovered by the BACI Program require that an Issue Report be initiated according to CCNPP procedure QL-2-100, "Issue Reporting and Assessments," in order to document and resolve the deficiency. The program requires that Issue Reports written due to discovery of leakage address the removal of boric acid residue and inspection of the components for corrosion. Issue Reports are initiated on discovery of corrosion and are required to address the evaluation of the component for continued service and corrective actions to prevent recurrences. [Reference 25, Sections 5.2 and 5.3]

The BACI Program is subject to periodic internal assessment. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 24, Section 1B.18]

The BACI Program has evolved to account for operational experience. For example, in 1989, an inservice inspection of Unit 2 pressurizer discovered evidence of reactor coolant leakage from approximately 28 of the 120 pressurizer heater penetrations and one upper level instrument nozzle. A Safety Evaluation was performed and as a result, CCNPP modified the inspection plan for the Unit 1 pressurizer heater sleeves and instrument nozzles. [Reference 25, Section 5.1.D; Reference 27]

Both CCNPP Units have had occurrences of boric acid leakage through the Incore Instrumentation flange connections. In March 1993 (Unit 2), and February 1994 (Unit 1), evidence of boric acid leakage and corrosion were discovered on the Incore Instrumentation flanges and flange nuts. The BACI Program existed at the time of these events, but only required specific inspection for leaks at the beginning and end of each outage. The program did not address leaks discovered outside of normal inspections. As a corrective action, the BACI Program was revised to ensure that all boric acid leaks are evaluated. [References 28 and 29]

The corrective actions taken as a result of the Issue Reports initiated by the BACI Program will ensure that the Group 2 components remain capable of performing their passive intended functions under all CLB conditions.

Group 2 (Device types with borated water or boric acid internal environments subject to crevice corrosion, general corrosion, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 2 components subject to crevice corrosion, general corrosion, and pitting:

- The Group 2 components have the passive intended functions to maintain pressure boundary integrity and provide containment isolation under CLB conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for the Group 2 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their passive intended functions under CLB conditions.
- Calvert Cliffs Technical Procedure CP-204 will mitigate the effects of crevice corrosion and pitting on the internal surfaces of the Group 2 components by maintaining primary system chemistry conditions such that impurities will be minimized, and contains acceptance criteria that ensure timely correction of adverse chemistry parameters.
- The CCNPP ARDI Program will conduct inspections of representative components to detect the effects of crevice corrosion and pitting, and will contain acceptance criteria that ensure corrective actions will be taken such that there is reasonable assurance that the passive intended functions will be maintained.
- The BACI Program will mitigate the effects of general corrosion by performing inspections on the external surfaces of the Group 2 components for signs of leakage or boric acid residue, and taking appropriate corrective action (e.g., removal of boric acid residue) prior to the onset of corrosion degradation.
- The BACI Program will conduct inspections to detect the effects of corrosion on the external surfaces of the Group 2 components, and will ensure corrective actions will be taken such that there is reasonable assurance that the passive intended functions will be maintained.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting will be managed for the Group 2 components such that they will be capable of performing their passive intended functions, consistent with the CLB, during the period of extended operation.

Group 3 (Device types with air internal environments subject to general corrosion) - Materials and Environment

As shown in Table 5.2-3, Group 3 applies to device types CV (air) and PCV that are subject to general corrosion. Group 3 consists of the pressurizer auxiliary spray control valve operator, the charging line to reactor coolant loop 1A control valve operator, the charging line to reactor coolant loop 2B control valve operator, and the associated pressure control valves that regulate the instrument air (IA) supply for the three control valve operators. [Reference 1, Attachment 1, Attachment 3s for Group IDs CV-10, PCV-01; Reference 6]

All of the Group 3 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

General corrosion is plausible for the following subcomponent parts: [Reference 1, Attachment 8]:

- CV - yoke, adjusting screw; and
- PCV - bolting.

The CV yoke is constructed of phosphated painted ductile iron and the adjusting screw is constructed of zinc plated steel. The PCV bolting is carbon steel. [Reference 1, Attachment 4s]

The internal environment for the Group 3 components is IA. The IA supply is normally supplied from the IA compressors and is very dry, filtered, oil-free air. Particle size, dew point, and oil hydrocarbons are controlled in accordance with industry standards. Occasionally, air that does not meet the same air quality standards may enter the IA System due to operation of the plant air compressors (minimal drying capacity) or the saltwater air compressors (no dryer) which serve as backups to the IA compressors. Therefore, there is a possibility that moisture may enter the IA supply, although its effect is expected to be limited since the backup compressors are operated on a short-term basis. An inspection performed on the piping immediately downstream of the saltwater air compressors, where the worst case of general corrosion is expected, revealed only very light surface rust on the inside of each piece. After more than 20 years in operation, approximately 60% of the pipe interior contained no rust and appeared similar to the inside of new pipe. Thickness measurements showed negligible loss of wall thickness. [Reference 1, Attachments 3 and 8; Reference 2, Section 9.10; Reference 30, Attachment 8]

Group 3 (Device types with air internal environments subject to general corrosion) - Aging Mechanism Effects

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. This ARDM is plausible for the Group 3 components because susceptible materials of construction are exposed to potentially moist air. However, the exposure of these components to moisture is expected to be minimal and short-term and is not expected to result in significant levels of degradation. [Reference 1, Attachment 6s, Attachment 7 for Valve Operators, Attachment 8]

This aging mechanism, if unmanaged, could eventually result in a loss of material such that the Group 3 components may not be able to perform their pressure boundary function under CLB conditions. Therefore, general corrosion was determined to be a plausible ARDM for which the aging effects must be managed for the Group 3 components.

Group 3 (Device types with air internal environments subject to general corrosion) - Methods to Manage Aging

Mitigation: The effects of general corrosion for the Group 3 components can be mitigated by minimizing their exposure to an aggressive environment (i.e., minimizing moisture in the IA supply). As discussed above, the exposure of these components to moisture is expected to be minimal and short-term and is not expected to result in significant levels of degradation. Continued maintenance of the IA System air quality to industry standards will ensure minimal component degradation. [Reference 1, Attachments 6s, Attachment 8]

Discovery: There are no methods deemed necessary to discover general corrosion since the aging effects can be mitigated by continued maintenance of the IA System air quality.

Group 3 (Device types with air internal environments subject to general corrosion) - Aging Management Program(s)

Calvert Cliffs initiated Preventive Maintenance Checklists IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality," following a review of recommendations from industry operating experience. The industry operating experience recommends maintaining the air quality within the requirements of Instrument Society of America (ISA) Standard ISA-S-7.3, "Quality Standard for Instrument Air." Standard ISA-S-7.3 recommends limits for maximum particle size, dew point temperature, and oil content. The checklists are performed in accordance with CCNPP Repetitive Tasks 10191024 (20121022), "Check Unit 1(2) Instrument Air Quality at System Low Points." Preventive Maintenance Checklists IPM 10000 (10001), check IA quality at three locations in the IA System: at the dryer outlet, at the furthest point from the dryer, and at the approximate mid-point between the other two. Measurements of dew point and particulate count are taken every 12 weeks. According to procedure, dew point data and particulate sample results are reviewed and trended. The responsible plant personnel determine if the air quality is abnormal, and initiate corrective action to return the air quality to normal and to investigate the condition of the dependent load internals as appropriate. This process ensures IA quality is maintained in accordance with industry standards for moisture (dew point). Operating experience relative to IA quality control has shown that the air normally provided is very dry and contains little particulate matter. [References 31 and 32]

Discovery: Since there are no methods deemed necessary to discover general corrosion, there are no programs credited with discovery of the aging effects due to this ARDM.

Group 3 (Device types with air internal environments subject to general corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 3 components subject to general corrosion:

- The Group 3 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- General corrosion is plausible for the Group 3 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- CCNPP Preventative Maintenance Checklists IPM 10000 (10001) will periodically monitor IA System air quality to maintain it in accordance with industry standards.

Therefore, there is reasonable assurance that the effects of general corrosion will be managed for the Group 3 components such that they will be capable of performing their pressure boundary function, consistent with the CLB, during the period of extended operation.

Group 4 (Shell side of heat exchangers subject to crevice corrosion and pitting) - Materials and Environment

As shown in Table 5.2-3, Group 4 applies to device type HX that is subject to crevice corrosion and pitting. Group 4 applies to the shell side of the Letdown Heat Exchanger. [Reference 1, Attachment 3 for Group ID HX-01]

The Letdown Heat Exchanger has the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

Crevice corrosion and pitting is plausible for the shell and welds. These subcomponent parts are constructed of carbon steel. [Reference 1, Attachments 4 and 5]

The internal environment on the shell side of the Letdown Heat Exchanger is CC System water. Stagnant flow conditions may be present in idled sections of the CC System. [Reference 1, Attachments 3 and 6]

Group 4 (Shell side of heat exchangers subject to crevice corrosion and pitting) - Aging Mechanism Effects

Carbon steel is susceptible to crevice corrosion and pitting in a stagnant, fluid environment. The aggressiveness of these corrosion mechanisms are particularly dependent on fluid chemistry conditions and oxygen levels. Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, and other mechanical joints that have a crevice geometry. 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. Crevice corrosion is closely related to pitting corrosion and can initiate pits (i.e., loss of material) in many cases. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. Pitting is a form of localized attack with greater corrosion rates at some locations than at others. This form of corrosion essentially produces holes of varying depth. High concentrations of impurity anions such as chlorides and sulfates tend to concentrate in the pit region, giving rise to a potentially aggressive solution in this zone. [Reference 1, Attachment 7 for Heat Exchangers]

Since the Group 4 components can be subject to stagnant fluid conditions which may allow impurities in the process fluid to concentrate, a potentially corrosive environment may exist. Therefore, crevice corrosion and pitting were determined to be plausible for the Group 4 components. [Reference 1, Attachment 6]

These aging mechanisms, if unmanaged, could eventually result in material loss such that the Group 4 components may not be able to perform their pressure boundary function under CLB conditions. Therefore, crevice corrosion and pitting were determined to be plausible ARDMs for which aging effects must be managed for the Group 4 components.

Group 4 (Shell side of heat exchangers subject to crevice corrosion and pitting) - Methods to Manage Aging

Mitigation: The effects of crevice corrosion and pitting for the Group 4 components can be mitigated by minimizing their exposure to an aggressive environment. Maintaining system chemistry conditions to minimize impurities will limit the rate and effects of degradation due to these ARDMs. [Reference 1, Attachment 6, Attachment 8]

Discovery: The degradation that does occur can be discovered and monitored by performing visual inspections of the heat exchanger shell and welds.

Group 4 (Shell side of heat exchangers subject to crevice corrosion and pitting) - Aging Management Program(s)

Mitigation: Calvert Cliffs Technical Procedure CP-206, "Specification and Surveillance for Component Cooling/Service Water Systems," is the program credited with managing the effects of crevice corrosion and pitting for the Group 4 components. The program provides for monitoring and maintaining CC System and Service Water System chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water, which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. Calvert Cliffs Technical Procedure CP-206 is based on the Technical Specifications, BGE's interpretation of industry standards, and recommendations made by Combustion Engineering. [Reference 33, Section 2.0; Reference 34, Attachment 8]

Calvert Cliffs Technical Procedure CP-206 describes the surveillance and specifications for monitoring the CC System fluid. CP-206 lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the CC System fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (normally not a radioactive system). [Reference 33, Attachment 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. If a target value or action level is not met, corrective actions are prescribed by the procedure, thereby ensuring timely response to chemical excursions. [Reference 33, Section 6.0.C, Attachment 1]

Operational experience related to CCNPP Technical Procedure CP-206 has shown no problems related to use of this procedure with respect to the CC System. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added to CP-206 to act as a method to discover any unusual corrosion of the CC System components. [Reference 35]

The chemistry program at CCNPP (which includes CP-206) is subject to periodic internal assessment. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program.

These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. [Reference 24, Section 1B.18]

Calvert Cliffs Technical Procedure CP-206 provides for a prompt review of CC System chemistry parameters so that steps can be taken to return chemistry parameters to normal levels and thus minimizing impurities which will limit the rate and effects of degradation due to corrosion mechanisms. [Reference 1, Attachment 8; Reference 33, Section 6.0.C]

Discovery: To verify that no significant crevice corrosion or pitting is occurring for the Group 4 components, a new plant program will be developed to provide requirements for inspections of representative components. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are discussed above in the Aging Management Program section for Group 2.

Group 4 (Shell side of heat exchangers subject to crevice corrosion and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 4 components subject to crevice corrosion and pitting:

- The Group 4 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Crevice corrosion and pitting are plausible for the Group 4 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- Calvert Cliffs Technical Procedure CP-206 will mitigate the effects of crevice corrosion and pitting by maintaining CC System chemistry conditions such that impurities will be minimized, and contains acceptance criteria that ensure timely correction of adverse chemistry parameters.
- The CCNPP ARDI Program will conduct inspections of representative components to detect the effects of crevice corrosion and pitting and will contain acceptance criteria that ensure corrective actions will be taken such that there is reasonable assurance that the pressure boundary function will be maintained.

Therefore, there is reasonable assurance that the effects of crevice corrosion and pitting will be managed for the Group 4 components such that they will be capable of performing their pressure boundary function, consistent with the CLB, during the period of extended operation.

Group 5 (Device types subject to wear) - Materials and Environment

As shown in Table 5.2-3, Group 5 applies to device types CKV and CV (Water) that are subject to wear. Group 5 consists of check valves and control valves whose internals are required to maintain a pressure boundary at a safety-related/non-safety-related interface or that have a containment isolation function.

[Reference 1, Attachment 1, Attachment 3s and 4s for Group IDs CKV-03, CKV-07, CKV-10, CKV-11, CV-02, CV-07, CV-09]

Wear is plausible for the following subcomponent parts: [Reference 1, Attachment 1]

- CKV - disc and spring (for some CKVs), and internals (for some CKVs); and
- CV - disc/cage (for some CVs), spindle and seat ring (for some CVs), and plug/cage (for some CVs).

The subcomponent parts that are subject to wear are constructed of stainless steel or stellite. [Reference 1, Attachment 4s]

The internal environment for the Group 5 components is borated water. [Reference 1, Attachment 3s]

Group 5 (Device types subject to wear) - Aging Mechanism Effects

The Group 5 valve internals are subject to wear due to the relative motion between the internal subcomponent parts during normal valve operation. Wear is dependent on frequency of valve operation and may cause the leak tightness of the valve to decrease with time. [Reference 1, Attachment 6s, Attachment 7 for Valves]

This aging mechanism, if unmanaged, could eventually result in a loss of leak tightness such that the Group 5 components may not be able to perform their pressure boundary and containment isolation functions under CLB conditions. Therefore, wear was determined to be a plausible ARDM for which the aging effects must be managed for the Group 5 components.

Group 5 (Device types subject to wear) - Methods to Manage Aging

Mitigation: Since the wear of the valve internal subcomponent parts is due to valve operation, decreased use of the valve would slow the degradation of the valve leak tightness. Proper material selection for the valve internal parts would also slow the effects of wear.

Discovery: For the valves required to maintain a pressure boundary at a safety-related/non-safety-related interface, the degradation that does occur due to wear can be discovered and monitored through visual inspections of the valve internals. For the valves that have a containment isolation function, the effects of wear can be managed by discovery of leakage during periodic leak rate testing.

Group 5 (Device types subject to wear) - Aging Management Program(s)

Mitigation: As discussed above, the effects of wear can be mitigated by decreased valve operation and by proper material selection. Decreased valve operation is not feasible from a plant operations standpoint. Therefore, it is concluded that there are no additional specific means deemed necessary to mitigate the effects of wear (in addition to proper material selection) because the inspection activities discussed in the Discovery section below are deemed adequate for effectively managing wear for the Group 5 components.

Discovery: To verify that no significant wear is occurring for the Group 5 valves required to maintain a pressure boundary at a safety-related/non-safety-related interface, a new plant program will be developed to provide requirements for inspections of representative components. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are discussed above in the Aging Management Program section for Group 2. [Reference 1 for Group IDs CKV-07, CKV-10, CV-07, CV-09]

The Group 5 valves that have a containment isolation function are associated with containment penetrations 1C and 2B, which are periodically tested as part of the CCNPP Local Leak Rate Test (LLRT) Program. [Reference 1, Attachment 1, Attachment 3s for Group IDs CKV-03, CKV-11, CV-02; Reference 2, Figure 5-10, Sheets 2 and 4; References 36 through 39]

The CCNPP LLRT Program is part of the overall CCNPP Containment Leakage Rate Testing Program. The CCNPP Containment Leakage Rate Testing Program was established to implement the leakage testing of the containment as required by 10 CFR 50.54(o) and 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B. Appendix J specifies containment leakage testing requirements, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. Containment leakage testing requirements include performance of Integrated Leakage Rate Tests, also known as Type A tests, and LLRTs, also known as Type B and C tests. Type A tests measure the overall leakage rate of the containment. Type B tests are intended to detect leakage paths and measure leakage for certain containment penetrations (e.g., airlocks, flanges, and electrical penetrations). Type C tests are intended to measure containment isolation valve leakage rates. [Reference 40, Section 6.5.6; References 41 and 42]

The CCNPP LLRT Program is based on the requirements of CCNPP Technical Specifications 3.6.1.2, 4.6.1.2, and 6.5.6. The scope of the program includes Type B and C testing of containment penetrations. The LLRT is performed on a performance-based testing schedule in accordance with Option B of 10 CFR Part 50, Appendix J, as implemented by CCNPP Technical Specifications. [References 40, 41, and 42]

Local leak rate testing presently includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- The test volume is pressurized to the LLRT Program test pressure, which is conservative with respect to the 10 CFR Part 50, Appendix J, test pressure requirements. Appendix J requires testing at a pressure "P_a," which is the peak calculated containment internal pressure related to the design basis accident.
- Leak rate, pressure, and temperature are monitored at the frequency specified by the LLRT procedure and the results are recorded.
- The maximum indicated leak rate is compared against administrative limits that are more restrictive than the maximum allowable leakage limits.
- "As found" leakage equal to or greater than the administrative limit, but less than the maximum allowable limit, is evaluated to determine if further testing is required and/or if corrective maintenance is to be performed.

- For “as found” leakage that exceeds the maximum allowable limit, plant personnel determine if Technical Specification Limiting Condition for Operation 3.6.1.2.b has been exceeded. Technical Specification 3.6.1.2.b contains the maximum allowable combined leakage for all penetrations and valves subject to the Type B and C tests. Corrective action is taken as required to restore the leakage rates to within the appropriate acceptance criteria.
- If any maintenance is required on a containment isolation valve that changes the closing characteristic of the valve, an “as left” test must be performed on the penetration to ensure leakage rates are acceptable.

The corrective actions taken as part of the LLRT Program will ensure that the Group 5 valves that have a containment isolation function will remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 5 (Device types subject to wear) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 5 components subject to wear:

- The Group 5 components have the passive intended functions to maintain the pressure boundary and to provide containment isolation under CLB conditions.
- Wear is plausible for the Group 5 valve internals which, if unmanaged, could eventually result in a loss of leak tightness such that the Group 5 components may not be able to perform their pressure boundary and containment isolation functions under CLB conditions.
- The CCNPP ARDI Program will conduct inspections of representative components to detect the effects of wear and will contain acceptance criteria that ensure corrective actions will be taken such that there is reasonable assurance that the pressure boundary function will be maintained.
- The CCNPP LLRT Program performs periodic testing to detect leakage, which may be a result of wear on the valve internals, and contains acceptance criteria that ensure corrective actions will be taken such that there is a reasonable assurance that the containment isolation function will be maintained.

Therefore, there is reasonable assurance that the effects of wear will be managed for the Group 5 components such that they will be capable of performing their pressure boundary and containment isolation functions, consistent with the CLB, during the period of extended operation.

Group 6 (Device types subject to vibrational fatigue) - Materials and Environment

As shown in Table 5.2-3, Group 6 applies to device types #HC, HV, PUMP, and RV that are subject to fatigue. [Reference 1, Attachment 1]

Group 6 consists of the following CVCS components: Charging Pumps, and the piping, hand valves, and relief valves between the Charging Pumps’ suction stabilizer and the Charging Pumps’ discharge desurger. These components are subjected to significant vibrational transients due to normal operation of the Charging Pumps. [Reference 1, Attachments 3, 5, and 6 for Group IDs #HC-03, HV-11, HV-12, PUMP-02, RV-04; Reference 6]

All of the Group 6 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

Fatigue is plausible for all of the above components due to vibrational transients. Calvert Cliffs Units 1 and 2 have experienced cases of fatigue failures in CVCS piping (in the late 1970s) that were attributed to vibrational loads imposed by operation of the Charging Pumps. The piping failures were typically small cracks in various welds, mostly in the Charging Pump suction lines. The cracks sometimes caused leaks in the CVCS piping. In response to these vibrational fatigue occurrences, BGE performed piping design modifications to reduce vibration and improve the CVCS reliability. [Reference 1, Attachment 1; Reference 43]

Fatigue is plausible for the following subcomponent parts: [Reference 1, Attachment 1, Attachment 5 for RV-04]

- #HC - pipe, fittings, flanges, studs, nuts, and welds;
- HV - body/bonnet, stem, studs, nuts, disc and seat (for some HVs), packing flange (for some HVs);
- PUMP - block and bolts; and
- RV - case, cylinder, adjusting bolt, spindle, disc, and spring.

The subcomponent parts for the Group 6 components that come in contact with the CVCS process fluid are primarily constructed of stainless steel. The Group 6 subcomponent parts external to the process stream (e.g., studs and nuts) are primarily constructed of alloy steel or carbon steel. The internal environment for the Group 6 CVCS components is borated water. [Reference 1, Attachment 3s and 4s]

Group 6 (Device types subject to vibrational fatigue) - Aging Mechanism Effects

Fatigue is the process of progressive localized structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points in the material. This process may culminate in cracks or complete fracture after a sufficient number of fluctuations. The fatigue life of a component is the number of cycles of stress or strain that it experiences before fatigue failure occurs. Failures may occur at either a high or low number of cycles in response to various kinds of loads (e.g., mechanical or vibrational loads, thermal cycles, or pressure cycles). High-cycle fatigue failure occurs when the component cyclic stresses (including modifying factors such as stress concentrations, surface conditions, and plating) exceed the material fatigue strength for the number of cycles. [Reference 1, Attachment 7s; Reference 17, Pages 14, 66]

High-cycle vibrational fatigue is plausible for all of the Group 6 components since they are subject to vibrational transients due to normal operation of the Charging Pumps [Reference 1, Attachment 6s]

This aging mechanism, if unmanaged, could eventually result in crack initiation and growth such that the Group 6 components may not be able to perform their pressure boundary function under CLB conditions. Therefore, vibrational fatigue was determined to be a plausible ARDM for which the aging effects must be managed for the Group 6 components.

Group 6 (Device types subject to vibrational fatigue) - Methods to Manage Aging

Mitigation: The effects of vibrational fatigue can be mitigated by reducing the severity of the vibrational transients experienced by the system by proper system design and material selection.

Discovery: The degradation that does occur due to vibrational fatigue can be discovered and monitored through visual inspections of the internal and external surfaces of the Group 6 components.

Group 6 (Device types subject to vibrational fatigue) - Aging Management Program(s)

Mitigation: As discussed above, the effects of vibrational fatigue can be mitigated by reducing the severity of the vibrational transients experienced by the system by proper system design and material selection. Design modifications were made to the CVCS to address vibrational fatigue problems experienced in the late 1970s (as described in the Materials and Environment section above). Therefore, there are no additional specific means deemed necessary to mitigate the effects of vibrational fatigue (in addition to proper system design and material selection) because the inspection activities discussed in the Discovery below are deemed adequate for effectively managing vibrational fatigue for the Group 6 components.

Discovery: To verify that no significant vibrational fatigue is occurring for the Group 6 components, a new plant program will be developed to provide requirements for inspections of representative components. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are discussed above in the Aging Management Program section for Group 2.

Group 6 (Device types subject to vibrational fatigue) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 6 components subject to vibrational fatigue:

- The Group 6 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Vibrational fatigue is plausible for the Group 6 components which, if unmanaged, could eventually result in crack initiation and growth such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The CCNPP ARDI Program will conduct inspections of representative components to detect the effects of vibrational fatigue, and will contain acceptance criteria that ensure corrective actions will be taken such that there is reasonable assurance that the pressure boundary function will be maintained.

Therefore, there is reasonable assurance that the effects of vibrational fatigue will be managed for the Group 6 components such that they will be capable of performing their pressure boundary function, consistent with the CLB, during the period of extended operation.

Group 7 (Device types subject to stress corrosion cracking) - Materials and Environment

As shown in Table 5.2-3, Group 7 applies to device types #HC, CKV, CV (Water), FE, HV, MOV, and RV that are subject to stress corrosion cracking. Group 7 consists of piping, valves, and flow elements that contain boric acid and have heat tracing. [Reference 1, Attachment 1, Attachment 3s and Attachment 6s for Group IDs #HC-02, #HC-05, #HC-06, CKV-02, CKV-06, CKV-07, CKV-08, CKV-10, CV-01, CV-09, FE-02, HV-06, HV-07, HV-14, MOV-03, MOV-04, RV-03, RV-05, RV-06]

All the Group 7 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

Stress corrosion cracking is plausible for the following subcomponent parts: [Reference 1, Attachment 1]

#HC - pipe, fittings, welds, and flanges;

CKV - body/bonnet;

CV (Water) - body/bonnet;

FE - element;

HV - body/bonnet;

MOV - body/bonnet; and

RV - case and cylinder (for some RVs); nozzle and body/bonnet (for some RVs).

The subcomponent parts that are subject to stress corrosion cracking are constructed of stainless steel. [Reference 1, Attachment 4s]

Electrical heat tracing is installed on the Group 7 components. The heat tracing is needed to maintain the boric acid above the saturation temperature. The heat tracing is designed to maintain 160°F; however, the operating temperature may be set lower. [Reference 2, Section 6.10]

Group 7 (Device types subject to stress corrosion cracking) - Aging Mechanism Effects

Stress corrosion cracking is selective corrosive attack along or across material grain boundaries. Stress corrosion cracking requires applied or residual tensile stress, susceptible materials (such as austenitic stainless steels, alloy 600, alloy X750, SAE 4340, and ASTM A289), and oxygen and/or ionic species (e.g., chlorides/sulfates). Common sources of residual stress include thermal processing and stress risers created during surface finishing, fabrication, or assembly. The heat input during welding can result in a localized sensitized region that is susceptible to stress corrosion cracking. Transgranular stress corrosion cracking (i.e., across the material grains) may be a concern in low alloy and stainless steel if aggressive chemical species (caustics, halogens, sulfates, especially if coupled with the presence of oxygen) are present. [Reference 1, Attachment 7s for Pipe, Valves, and Elements]

Stress corrosion cracking is plausible for the Group 7 components because external surfaces of the stainless steel subcomponents are in contact with halogens and are subject to high temperatures due to the heat tracing. The halogens are found in the adhesives used to adhere the heat tracing to the component exterior surfaces. The stress corrosion cracking could lead to minor breeches of the pressure boundary and subsequent boric acid leakage. [Reference 1, Attachment 6s]

Operating experience at CCNPP includes at least one case of externally-initiated stress corrosion cracking in CVCS heat-traced piping . Transgranular cracking was observed on the boric acid recirculation line. Analysis of the cracked piping determined that the cause of the failure was due to the presence of chlorides under high temperature conditions due to the heat tracing. The potential chloride sources were determined to be from the heat tracing adhesive, insulation, or residual chloride contamination from construction. Nuclear industry operating experience has also identified heat tracing as contributing to cracking of stainless steel piping in the presence of chlorides. [Reference 44]

This aging mechanism, if unmanaged, could eventually result in cracking such that the Group 7 components may not be able to perform their pressure boundary function under CLB conditions. Therefore, stress corrosion cracking was determined to be a plausible ARDM for which the aging effects must be managed for the Group 7 components.

Group 7 (Device types subject to stress corrosion cracking) - Methods to Manage Aging

Mitigation: Stress corrosion cracking can be mitigated by minimizing the exposure of the stainless steel subcomponents to an aggressive environment for corrosion. Removing the corrosive adhesive associated with the heat tracing (and choosing another method to adhere the heat tracing) will mitigate the effects of stress corrosion cracking.

Discovery: Since the effects of stress corrosion cracking can be mitigated as described above, there are no additional methods deemed necessary to manage this ARDM.

Group 7 (Device types subject to stress corrosion cracking) - Aging Management Program(s)

Mitigation: A plant modification was initiated in 1991 to replace the original heat tracing in the CVCS. The existing heat tracing adhesive will be removed, eliminating the halogen impurities that promote stress corrosion cracking. The new heat tracing will be installed with an adhesive that contains no halogen impurities. Portions of the original heat tracing have already been replaced. The modification will be completely implemented prior to the start of the license renewal period. Implementation of this modification will render this ARDM as no longer plausible. [Reference 1, Attachment 6s, Attachment 8]

Discovery: As discussed in the Mitigation section above, since the plant modification will render stress corrosion cracking as non-plausible after the modification is completely implemented, there are no discovery programs deemed necessary to manage this ARDM.

Group 7 (Device types subject to stress corrosion cracking) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 7 components subject to stress corrosion cracking:

- The Group 7 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Stress corrosion cracking is plausible for the Group 7 components which, if unmanaged, could eventually result in cracking such that the Group 7 components may not be able to perform their pressure boundary function under CLB conditions.
- A plant modification was initiated to replace the original heat tracing and removes the potentially corrosive adhesive from the Group 7 components. The modification will be completely implemented prior to the start of the license renewal period and will render this ARDM as no longer plausible.

Therefore, there is reasonable assurance that the effects of stress corrosion cracking will be managed for the Group 7 components such that they will be capable of performing their pressure boundary function, consistent with the CLB, during the period of extended operation.

5.2.3 Conclusion

The programs discussed for the CVCS are listed in the following table. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the CVCS components will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 5.2-4
LIST OF AGING MANAGEMENT PROGRAMS FOR THE CVCS

	Program	Credited For
Existing	CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring"	Monitoring and management of the effects of thermal fatigue for the Group 1 components.
Existing	CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program"	Mitigation, detection, and management of the effects of crevice corrosion, general corrosion, and pitting for the Group 2 components.
Existing	CCNPP Preventative Maintenance Checklists IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality"	Mitigation of the effects of general corrosion for the Group 3 components.
Existing	CCNPP Technical Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems"	Mitigation of the effects of crevice corrosion and pitting for the Group 4 components.
Existing	CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems"	Mitigation of the effects of crevice corrosion and pitting for the Group 2 components.
Existing	LLRT Program CCNPP Surveillance Test Procedure M-571A-1(2), "Local Leak Rate Test, Penetrations 1A, 1B, 1C" CCNPP Surveillance Test Procedure M-571C-1(2), "Local Leak Rate Test, Penetrations 2A, 2B"	Detection and management of leakage that could be the result of wear for the Group 5 components.
Existing	Plant Modification	Mitigation of the effects of stress corrosion cracking for the Group 7 components.
New	ARDI Program	Detection and management of the effects of crevice corrosion and pitting for the Group 2 and Group 4 components. Detection and management of the effects of vibrational fatigue for the Group 6 components. Detection and management of the effects of wear for the Group 5 components.

5.2.4 References

1. "CCNPP Aging Management Review Report for the Chemical and Volume Control System (System 041)," Revision 2, March 19, 1997
2. CCNPP Updated Final Safety Analysis Report, Revision 20
3. "CCNPP System Level Scoping Results," Revision 4, April 6, 1995
4. "CCNPP Component Level Scoping Results for the Chemical and Volume Control System (System 041)," Revision 2, April 9, 1996
5. CCNPP Drawing 60730SH0001, "Chemical and Volume Control System," Revision 67
6. CCNPP Drawing 60730SH0002, "Chemical and Volume Control System," Revision 49
7. CCNPP Drawing 60730SH0003, "Chemical and Volume Control System," Revision 33
8. CCNPP Drawing 62730SH0001, "Chemical and Volume Control System," Revision 61
9. CCNPP Drawing 62730SH0002, "Chemical and Volume Control System," Revision 39
10. CCNPP Drawing 62730SH0003, "Chemical and Volume Control System," Revision 32
11. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 1, August 30, 1996
12. CCNPP Drawing 92767SH-HC-1, "M-600 Piping Class Sheets," Revision 55
13. CCNPP Drawing 92767SH-CC-1, "M-600 Piping Class Sheets," Revision 48
14. "CCNPP Pre-Evaluation Results for the Chemical and Volume Control System (System 041)," Revision 2, October 17, 1996
15. CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," Revision 0, February 28, 1996
16. Combustion Engineering Owners Group Task 571, Report No. CE-NPSD-634-P, "Fatigue Monitoring Program for Calvert Cliffs Nuclear Power Plants Units 1 and 2," April 1992
17. "Metal Fatigue in Engineering," H. O. Fuchs and R. I. Stephens, John Wiley & Sons, Copyright 1980
18. CCNPP "Fatigue Monitoring Report for 1996," Final Report for 1996 generated by CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," March 25, 1997
19. Letter from Mr. J. P. Durr (NRC) to Mr. C. Stoiber *(sic)* (BGE), dated February 11, 1993, "Inspection Report Nos. 50-317/92-32 and 50-318/92-32"
20. BGE Procurement Specification 6422284S, "Technical Services to Evaluate Thermal Fatigue Effects on Calvert Cliffs Nuclear Power Plant Systems Requiring Aging Management Review for License Renewal," Revision 0, July 29, 1996
21. NUREG-0933, Generic Safety Issue 166, "Adequacy of Fatigue Life of Metal Components," Revision 1, June 30, 1995
22. CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems," Revision 7, March 11, 1997

23. CCNPP Nuclear Program Directive, CH-1, "Chemistry Program," Revision 1, December 13, 1995

24. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48, March 28, 1997

25. CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program." Revision 1, December 15, 1994

26. NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988

27. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated July 29, 1994, "Pressurizer Heater Sleeves and Instrument Nozzles Inspection Plan Modification / Heater Sleeves Nickel Plating"

28. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 29, 1994, "Licensee Event Report 94-004, Revision 1, Excessive Corrosion of Incore Instrumentation Flange Components"

29. Letter from Mr. L. T. Doerflein (NRC) to Mr. R. E. Denton (BGE), dated October 16, 1995, "NRC Region I Inspection Report Nos. 50-317/95-08 and 50-318/95-08"

30. CCNPP "Aging Management Review Report for the Compressed Air System," Revision 4, August 11, 1997

31. CCNPP Nucleis Database, Preventative Maintenance Checklists IPM 10000 (10001), "Check Unit 1 (2) Instrument Air Quality"

32. CCNPP Nucleis Database, Repetitive Tasks 10191024 (20191022), "Check Unit 1 (2) Instrument Air Quality at Selected System Low Points"

33. CCNPP Technical Procedure CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3, November 4, 1996

34. "CCNPP Aging Management Review Report for the Component Cooling System," Revision 1, November 7, 1996

35. CCNPP 1996 Component Cooling and Service Water System Assessment, February 26, 1997

36. CCNPP Unit 1 Surveillance Test Procedure M-571A-1, "Local Leak Rate Test, Penetrations 1A, 1B, 1C," Revision 0, May 16, 1991

37. CCNPP Unit 2 Surveillance Test Procedure M-571A-2, "Local Leak Rate Test, Penetrations 1A, 1B, 1C," Revision 0, October 17, 1991

38. CCNPP Unit 1 Surveillance Test Procedure M-571C-1, "Local Leak Rate Test, Penetrations 2A, 2B," Revision 0, May 17, 1991

39. CCNPP Unit 2 Surveillance Test Procedure M-571C-2, "Local Leak Rate Test, Penetrations 2A, 2B," Revision 0, October 17, 1991

40. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), dated March 7, 1997, "Issuance of Amendments for CCNPP Unit No. 1 (TAC No. M96350) and Unit No. 2 (TAC No. M96351)" (Amendments 221/197)

41. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"

42. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated November 26, 1996, "License Amendment Request; Adoption of 10 CFR Part 50, Appendix J, Option B for Types B and C Testing"

43. Letter from Mr. R. W. Reid (NRC) to Mr. A. E. Lundvall, Jr. (BGE) dated October 18, 1980, "Safety Evaluation Regarding Charging Pump Pipe Vibration"

44. NRC IE Information Notice No. 85-34, "Heat Tracing Contribute to Corrosion Failure of Stainless Steel Piping," April 30, 1985

5.3 Component Cooling System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Component Cooling (CC) System. The CC System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.3.1 Scoping

System level scoping describes boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.3.1.1 presents the results of the system level scoping, 5.3.1.2 the results of the component level scoping, and 5.3.1.3 the results of scoping to determine components subject to AMR.

Representative historical operating experience pertinent to aging is included in appropriate areas, to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

5.3.1.1 System Level Scoping

This section begins with a description of the system which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description/Conceptual Boundaries

The CC System is designed to remove heat from various power plant auxiliary systems. The Saltwater (SW) System provides the cooling medium for the CC heat exchangers. The CC System serves as an intermediate barrier between the various supplied auxiliary systems and the SW System. System components are rated for maximum duty requirements during normal and shutdown cooling operation and are also capable of removing heat during a loss-of-coolant accident. [Reference 1, Section 1.1.1]

The CC System for each unit consists of three motor-driven CC circulating pumps, two CC heat exchangers, a head tank, a chemical additive tank, associated valves, piping, instrumentation, and controls. [Reference 1, Section 1.1.1]

The CC heat exchangers are designed for a CC supply temperature of 95°F, with a saltwater cooling supply temperature of 90°F, at normal operating conditions. The CC System fluid may reach a temperature as high as 120°F during a loss-of-coolant accident prior to a recirculation actuation signal (RAS), and during plant cool-down and cold shutdowns. [Reference 2, Section 9.5.2.1]

A head tank allows for expansion of the CC System water and provides sufficient net positive suction head for the CC pumps. Makeup can be added to the CC System to maintain head tank level. The source of makeup water is the plant Demineralized Water System. Additional makeup capacity may be provided from the Condensate System. [Reference 2, Section 9.5.2.1]

A chemical additive tank connected to the system permits maintenance of the proper corrosion inhibitor concentration in the CC System. Calvert Cliffs Updated Final Safety Analysis Report Figures 9-6 (Unit 1) and 9-25 (Unit 2) show the schematic diagram of the CC System. The components cooled by the CC System include the following: [Reference 2, Section 9.5.2.1]

- Letdown heat exchanger;
- Shutdown cooling heat exchangers;
- Miscellaneous waste processing heat exchanger;
- Waste gas compressor aftercoolers and jacket coolers;
- Control element drive mechanism coolers;
- Reactor coolant pump mechanical seals and lube oil coolers;
- Low pressure safety injection pump seals and coolers;
- High pressure safety injection pump seals and coolers;
- Containment penetration cooling;
- Reactor support cooling;
- Steam generator lateral support cooling;
- Coolant waste evaporators;
- Reactor coolant and miscellaneous waste sampling system;
- Degasifier vacuum pump cooler;
- Post-accident sample system; and
- Reactor coolant drain tank heat exchanger.

During normal plant operation, one of the CC pumps and one of the CC heat exchangers are required for cooling service. During normal RCS cool-down from 300°F to 140°F, two CC pumps and two CC heat exchangers are required to provide maximum heat removal. For long-term cooling following a loss-of-coolant accident, two CC pumps and two CC heat exchangers provide the necessary cooling capacity for both shutdown heat exchangers. Component cooling will be supplied to both shutdown cooling heat exchangers because of the normally-open cross-tie. [Reference 2, Section 9.5.2.1]

The CC pump motors are supplied from two separate 480 volt engineered safety feature busses, with the third pump motor having two breakers, one from each bus. If a loss of offsite power occurs, the pumps' electrical power requirements can be supplied by the emergency diesel generators. During normal shutdown cooling, two pumps are running with the third pump on standby. If low discharge header pressure is annunciated in the Control Room, the operator can start the third pump. [Reference 2, Section 9.5.2.1]

The CC System is comprised of the following equipment types: [Reference 1, Section 1.1.2]

Piping/tubing	Transport cooling water from the CC pumps to the various loads.
Valves	Control, pressure control, check, hand, solenoid and relief valves that provide containment isolation and system alignment/isolation; automatic vents that release air from the system.
Instruments	Measure flow rates, pressure, temperature, and radiation. Provide alarm and initiate automatic corrective action.
Pumps	Pump cooling water through CC heat exchangers to reactor plant and auxiliary system components.
Heat Exchangers	Transfer heat from reactor plant and auxiliary system components to the CC System and between the CC System and the SW System. Aging management review of the CC/SW Heat Exchangers is included with the SW System review in Section 5.16 of the BGE LRA, and review of the load heat exchangers for interfacing systems are included with the review of their respective systems.
Tanks	Act as surge volumes for the system and allow for chemical addition to system.

The CC System intended system functions are: [Reference 1, Section 1.1.3]

- Provide Containment Isolation during a Design Basis Event.
- Provide support as a vital auxiliary for Containment Spray process fluid cooling (via shutdown cooling heat exchanger) and high pressure safety injection and low pressure safety injection pump cooling.
- Provide information used to assess the plant and environs condition during and following an accident.
- Maintain functionality of electrical components as addressed by the Environmental Qualification (EQ) program.
- Provide a heat sink for essential shutdown cooling loads to ensure safe shutdown in the event of a postulated severe fire.
- Provide seismic integrity and protection of safety-related components.
- Maintain electrical continuity and provide protection of the electrical system.
- Maintain electrical continuity and provide protection of the electrical system (this includes only device types that perform the function by exhibiting motion or changing properties or configuration).
- Maintain the pressure boundary of the system (liquid).
- Provide alternate heat sink via the unaffected unit for essential shutdown cooling loads in the event of a severe fire in the CC Room.

System Operating Experience

The following are operating experiences related to the CC System with the potential for affecting the intended functions of the components or system.

Operating experience relative to the CC heat exchangers is located in the SW License Renewal Technical Report in Section 5.16 of the BGE LRA. Operating experience events relevant to the CC System involve leakage from the CC cross-connect valves. Due to a combination of poor design and aging, some of the CC cross-connect valves were experiencing minor leakage. Baltimore Gas and Electric Company removed and replaced the CC System cross-connect valves with an upgraded valve design. There has been no further observable valve leakage since the replacement of the CC cross-connect valves.

Calvert Cliffs has experienced water hammers in the CC System while switching the CC pumps. The cause of these water hammers was determined to originate from CC pump outlet check valves. Baltimore Gas and Electric Company plans to replace these check valves to eliminate further water hammer.

The CC System operational history has shown that it is a very leak tight system, which typically leaks less than one gallon per minute during normal operation (due to pump, auto vents, and valve packing leakage). During inspection of the CC System it was noted that a very tightly adhering layer of magnetite has formed on the interior surfaces of the system. The formation of a passive oxide layer (magnetite) on the interior surface of the CC components protects them from corrosion by minimizing the exposure of bare metal to system fluids.

These events demonstrate that CCNPP inspects, maintains, and upgrades the CC System to ensure that the CC components remain capable of performing their intended function under current licensing basis (CLB) conditions.

System Interfaces

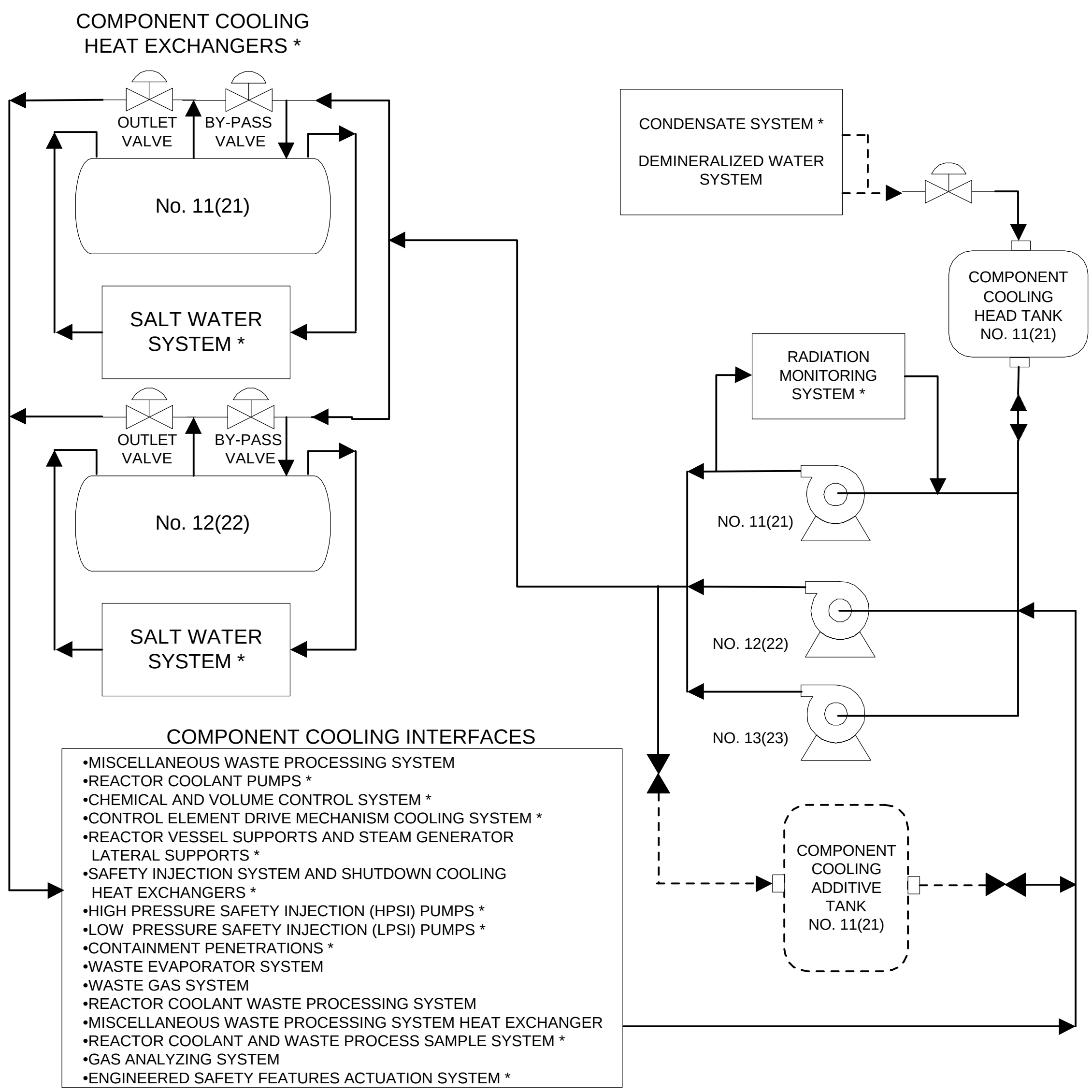
Figure 5.3-1 shows the CC System flow path and components, including the systems and components that interface with the CC System. A list of CC System interfaces is given below: [Reference 1, Section 1.1.2]

- Demineralized Water System
- Condensate System*
- Radiation Monitoring System*
- Saltwater System*
- Miscellaneous Waste Processing System
- Reactor Coolant Pumps*
- Chemical and Volume Control System*
- Control Element Drive Mechanism Cooling System*
- Reactor Vessel Supports and Steam Generator Lateral Supports*
- Safety Injection System and Shutdown Cooling Heat Exchangers*
- High Pressure Safety Injection Pumps*
- Low Pressure Safety Injection Pumps*

- Containment Penetrations*
- Waste Evaporator System
- Waste Gas System
- Reactor Coolant Waste Processing System
- Miscellaneous Waste Processing System Heat Exchanger
- Reactor Coolant and Waste Process Sample System*
- Gas Analyzing System
- Engineered Safety Features Actuation System*

The CC System interfaces listed above are not all within the scope of license renewal. Those systems or system components interfacing with the CC System that are within the scope of license renewal are noted with an asterisk (*) above and in Figure 5.3-1. The asterisk indicates that the system or component is within the scope of license renewal. However, the CC System at that interface may not be within the scope of license renewal (i.e., non-safety-related CC piping at the reactor vessel and steam generator lateral supports). Where a system, component, commodity, or structure interface is in scope for license renewal, that system will be addressed by the respective section of this application for that system, component, commodity, or structure.

SIMPLIFIED DIAGRAM
(FOR INFORMATION ONLY)



LEGEND

* THIS INTERFACE SYSTEM/COMPONENT IS WITHIN THE SCOPE OF LICENSE RENEWAL. (WLSR)

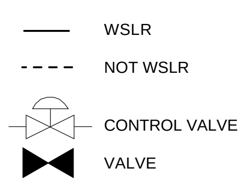


FIGURE 5.3-1

CCNPP COMPONENT COOLING SYSTEM

System Scoping Results

The CC System is in the scope for license renewal based on 10 CFR 54.4(a). In accordance with Section 4.1.1 of the CCNPP IPA Methodology, the following system intended functions were determined based on the requirements of 10 CFR 54.4(a)(1) and (2): [Reference 3, Table 1]

- To provide containment isolation;
- To act as a vital auxiliary for containment spray process fluid cooling (via shutdown cooling heat exchangers) and high pressure safety injection/low pressure safety injection pump cooling;
- To provide seismic integrity and/or protection of safety-related components;
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To maintain the pressure boundary of the system liquid

The following intended functions of the CC System were determined based on the requirements of 10 CFR 54.4(a)(3): [Reference 3, Table 1]

- For EQ (§50.49) - Maintain functionality of the electrical components as addressed by the EQ program.
- For fire protection (§50.48) - Provide heat sink for essential shutdown cooling loads to ensure safe shutdown in the event of a postulated severe fire.
- For fire protection (§50.48) - Provide alternative heat sink via the unaffected unit for essential shutdown cooling loads in the event of a severe fire at the CC Room.
- For post-accident monitoring - To provide information used to assess the environs and plant condition during and following a Design Basis accident.

All of the CC components performing 10 CFR 54.4(a)(1) and (2) intended functions are safety related, and component ratings and construction information is identified in the Updated Final Safety Analysis Report Section 9.5, Table 9-17.

5.3.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the CC System that is within the scope of license renewal includes equipment types that consist of: piping; components (i.e., heat exchangers, pumps, valves, and tanks); supports; instrumentation; and cables for the section of the system relied on for mitigation of Design Basis Events, EQ and fire protection.

A total of 36 device types within these CC equipment types were designated as within the scope of license renewal based on these intended functions. These device types are listed in Table 5.3-1. [Reference 1, Section 2.2]

Several component types are common to many plant systems and perform the same passive functions regardless of system. These component types are listed below:

- Structural supports for piping, cables and components;
- Electrical cabling; and

- Process and instrument tubing, instrument tubing manual valves, and tubing supports for components.

5.3.1.3 Components Subject to Aging Management Review

This section describes the components of the CC System which are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the device types previously listed as either associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with the CCNPP IPA Methodology Section 5.1, the following CC System functions were determined to be passive: [Reference 1, Table 3-1]

- To maintain the pressure boundary of the system liquid;
- To provide seismic integrity and/or protection of safety-related (SR) components; and
- To maintain electrical continuity and/or provide protection of the electrical system.

TABLE 5.3-1

COMPONENT COOLING DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Type	Device Code
• Piping Line	(-HB)
• Automatic Vent	(AVV)
• Check Valve	(CKV)
• Coil	(COIL)
• Control Valve	(CV)
• Disconnect Switch/Link	(DISC)
• Voltage/Current Device	(E/I)
• Fuse	(FU)
• Hand Switch	(HS)
• Hand Valve	(HV)
• Heat Exchanger	(HX)
• Ammeter	(II)
• Power Light Indicator	(JL)
• Level Gage	(LG)
• Level Switch	(LS)
• Level Transmitter	(LT)
• 480V Motor	(MB)
• 125/250 VDC Motor	(MD)
• Pressure Differential Indicator	(PDIS)
• Pressure Indicator	(PI)
• Panel	(PNL)
• Pressure Switch	(PS)
• Pressure Transmitter	(PT)
• Pump/Driver Assembly	(PUMP)
• Radiation Element	(RE)
• Relief Valve	(RV)
• Relay	(RY)
• Solenoid Valve	(SV)
• Temperature Element	(TE)
• Temperature Indicator	(TI)
• Temperature Indicator Alarm	(TIA)
• Temperature Indicating Controller	(TIC)
• Tank	(TK)
• Power Supply	(YX)
• Position Indicating Lamp	(ZL)
• Position Switch	(ZS)

Device Types Subject to Aging Management Review

The device types of the CC System, and the associated supports, cables, and tubing, were reviewed and were dispositioned as follows: [Reference 1, Section 3-2, Table 3-2]

- Fifteen device types including the coil, disconnect link switch, voltage/current device, fuse, hand switch, ammeter, power light indicator, 480 VAC motor, 125/250 VDC motor, pressure indicator, relay, temperature indicating alarm, power supply, position indicating lamp and position switch are only associated with active functions.
- The pressure transmitter device type is subject to replacement.
- The CC heat exchanger is evaluated in the SW System section (Section 5.16) of the BGE LRA.
- Six device types including the level gauge, level switch, level transmitter, differential pressure indicating switch, and pressure switch are evaluated in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE License Renewal. The sixth device type, panel, is dispositioned in the Electrical Panels Commodity Evaluation in Section 6.2 of the BGE LRA.
- Structural supports for piping, cables and components in the CC System that are subject to AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA. This commodity evaluation completely addresses the CC System passive intended function, "To provide seismic integrity and/or protection of safety-related components."
- Maintaining functionality of the electrical components in the CC System that are subject to AMR is evaluated for the effects of aging in the EQ Commodity Evaluation in Section 6.3 of the BGE LRA. This commodity evaluation completely addresses the CC System intended function, "To maintain functionality of electrical components."
- Electrical cabling for components in the CC System that are subject to AMR is evaluated for the effects of aging in the Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the CC System passive intended function, "To maintain electrical continuity and/or provide protection of the electrical system."
- Instrument tubing and piping, instrument valves, and fittings (generally everything from the outlet of the final root valve up to and including the instrument) are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. This commodity evaluation addresses the CC System passive intended function, "To maintain the pressure boundary of the system (liquid)."

As a result of the evaluations described above, the only passive function associated with the CC System not previously dispositioned is the following:

- To maintain the pressure boundary of the system (liquid).

Of the 36 device types originally within the scope of license renewal, 13 device types remain that have this passive intended function (pressure boundary) and are long-lived. These 13 CC device types are exposed to treated demineralized water and are listed in Table 5.3-2. The 13 device types are subject to AMR for the CC System, and are the subject of the remainder of this report. [Reference 1, Table 3-2]

TABLE 5.3-2
DEVICE TYPES REQUIRING AMR FOR COMPONENT COOLING SYSTEM

Piping (-HB)
Automatic Vent (AVV)
Check Valve (CKV)
Control Valve (CV)
Hand Valve (HV)
Pump/Driver Assembly (PUMP)
Radiation Element (RE)
Relief Valve (RV)
Solenoid Valve (SV)
Temperature Element (TE)
Temperature Indicator (TI)
Temperature Indicating Controller (TIC)
Tank (TK)

5.3.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the CC System device types is given in Table 5.3-3. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate column. For the AMR, some CC device types have a number of groups associated with them because of the diversity of materials used in their fabrication. A check mark (✓) indicates that the ARDM applies to at least one group for the device type listed. The device types listed in Table 5.3-3 are those previously identified in Table 5.3-2 as passive and long-lived. [Reference 1, Table 4-1, 4-2] For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped where there are similar characteristics and the discussion is applicable to all device types within that group. Exceptions are noted where appropriate. For this report the device types are grouped according to ARDMs.

The following discussions present information on plausible ARDMs. The discussions are grouped by ARDM, the device type groups that are affected by each, the materials and environment pertinent to the ARDM, the methods to manage aging, aging mechanism effects, and the aging management program(s). There is then a summary of the aging management demonstration. The groups addressed here are:

Group 1 - crevice corrosion/pitting;
Group 2 - erosion corrosion;
Group 3 - general corrosion;
Group 4 - rubber degradation;
Group 5 - selective leaching; and
Group 6 - wear.

Crevice corrosion and pitting are grouped together in this report because they both affect the same device type groups, have similar effects, and are covered by the same aging management programs.

TABLE 5.3-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE COMPONENT COOLING SYSTEM

Potential ARDMs	Device Types for Which ARDM is Plausible												
	-HB	AVV	CKV	CV	HV	PUMP	RE	RV	SV	TE	TI	TIC	TK
Cavitation Corrosion													
Corrosion Fatigue													
Crevice Corrosion	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)
Dynamic Loading													
Electrical Stressors													
Erosion/Corrosion	✓(2)												
Fatigue													
Fouling													
Galvanic Corrosion													
General Corrosion	✓(3)		✓(3)	✓(3)	✓(3)	✓(3)		✓(3)		✓(3)	✓(3)		✓(3)
Hydrogen Damage													
Intergranular Attack													
MIC													
Particulate Wear Erosion													
Pitting	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)	✓(1)
Radiation Damage													
Rubber Degradation				✓(4)									
Saline Water Attack													
Selective Leaching		✓(5)		✓(5)	✓(5)			✓(5)	✓(5)				
Stress Corrosion Cracking													
Thermal Damage													
Thermal Embrittlement													
Wear			✓(6)	✓(6)				✓(6)					

MIC - Microbiologically Influenced Corrosion
✓ indicates plausible ARDM determination
(#) indicates the group in which this ARDM is evaluated

Note: Not every group within the device types listed here may be susceptible to a given ARDM. This is because groups within a device type are not always fabricated from the same materials. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

Group 1 (crevice corrosion/pitting) - Materials and Environment

Table 5.3-3 shows that crevice corrosion/pitting is plausible for all the device types listed. The following CC System device types, and the material characteristics which are susceptible to these ARDMs, are listed below: [Reference 1, Attachment 1 and -HB01, AVV01, CV01/02/03/04/05, CKV01/02, HV01/02/03/04/05/06/07, PUMP01, RE01, RV01, RV01/02/03, SV01, T101, TIC01, TK01 Attachments 4, 5 and 6]

- Piping - carbon steel;
- Automatic vents - cast brass base and shell with stainless steel float/pins;
- Check valves - some have carbon steel bodies and discs;

- Control valves - some groups have carbon steel bodies, some have stainless steel bodies, shafts and discs, some have cast iron bodies, and some have aluminum bronze discs;
- Hand valves - some groups have carbon steel bodies; some have stainless steel bodies, stems, and discs; and some have cast iron bodies/discs;
- Pump - carbon steel casing;
- Radiation elements - stainless steel;
- Relief valve - some groups have carbon steel bodies; some have stainless steel bodies, seat, and disc; some have bronze bodies, and brass seats and discs;
- Solenoid valve - brass;
- Temperature elements - carbon steel (TE included in TI device type in Reference 1, Attachment 1);
- Temperature indicators - carbon steel;
- Temperature indicating controllers - stainless steel; and
- Tanks - carbon steel.

The internal environment of the CC System is chemically-treated water at a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 2, Section 9.5.2.1, Table 9-17] The CC System includes of a number of components (i.e., valves, instruments) that are flange bolted, welded in place, or are gasketed. Within the CC System there are regions of low or stagnant coolant flow conditions.

Group 1 (crevice corrosion/pitting) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. 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. Crevice corrosion is closely related to pitting and can initiate pits in many cases. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. Pitting is a form of localized attack with greater corrosion rates at some locations than at others. These pits are, in many cases, filled with oxide debris, especially in ferritic materials such as carbon steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non-passive metals. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. It can also occur at locations of relatively stagnant coolant or water, such as in carbon steel piping of cooling systems. [Reference 1, Pipe-Attachment 7]

Long-term exposure to environments conducive to these ARDMs may result in crevice corrosion/pitting which, if left unmanaged, could eventually result in loss of material and pressure-retaining capability under CLB design loading conditions. Therefore, crevice corrosion/pitting have been determined to be plausible ARDMs for which aging effects must be managed for the CC System.

Group 1 (crevice corrosion/pitting) - Methods to Manage Aging

Mitigation: Maintaining an environment of purified water with controls on pH, suspended solids, and chlorides during normal plant operation can mitigate this ARDM. [Reference 1, Pipe Attachment 6] The initial formation of a passive oxide layer (magnetite) on the interior surface also mitigates the effects of crevice corrosion/pitting by minimizing the exposure of bare metal to system fluids.

Discovery: Inspection of a representative sample of susceptible areas of the system for the signs of crevice corrosion/pitting could identify whether this ARDM is actually occurring in the CC System. Maintenance/overhaul of CC System components also provides opportunities to inspect for signs of crevice corrosion/pitting.

Group 1 (crevice corrosion/pitting) - Aging Management Program(s)

Mitigation: Calvert Cliffs Chemistry Procedure (CP) CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," provides for monitoring and maintaining CC chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 1, Attachment 8]

Procedure CP-206 describes the surveillance and specifications for monitoring the CC System fluid. Procedure CP-206 lists the parameters to monitor, the frequency of monitoring these parameters, and the Target and Action Levels for the CC System fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (normally not a radioactive system). [Reference 4, Attachment 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have Action Levels associated with them. For pH the current Action Level is less than 9.0 or greater than 9.8; for hydrazine the current Action Level is less than 5 or greater than 25 parts per million (ppm). Refer to Attachment 1 in CP-206 for the specific monitoring frequency and Target Values for each chemistry parameter. [Reference 4, Attachment 1]

Operational experience related to CP-206 has shown no problems related to use of this procedure with respect to the CC System. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added as a parameter to CP-206 to discover any unusual corrosion of the CC carbon steel components.

An internal BGE chemistry summary report for 1996 described the CCNPP Unit 1 and Unit 2 CC/SRW Systems' chemistry as excellent. Action levels for all four systems were only exceeded on eight occasions, or approximately 0.7% of the time during the year. Over 70% of the Action Levels exceeded were due to major system changes during the 1996 refueling outage. Recommendations to correct this condition have been made to determine outage evolutions that can affect the CC/SRW chemistry and take action to prevent chemistry targets being exceeded.

The CC System usually operates within normal parameters, except when the system is restarted after an outage lay-up. During an outage lay-up, the CC System experiences some minor corrosion when the internal component surfaces are exposed to air. After the CC System is returned to service and flow is once again established, some of this minor corrosion is removed from the pipe inner surface and released into the system where it is detected. An increase in suspended solids (due to this effect) was seen on Unit 1 at the start of the 1996 outage, and was correlated to flow initiation through the Shutdown Cooling Heat Exchangers. The level of suspended solids slowly decreased over the course of the year back to levels obtained before the outage. The Unit 2 suspended solids showed a fairly steady baseline with a few minor spikes occurring during the year.

Procedure CP-206 provides for a prompt review of CC chemistry parameters so that steps can be taken to return chemistry parameters to normal levels, and thus minimizes the effects of crevice corrosion/pitting.

Discovery: Although minimal corrosion is expected, the CC System will be included in the Age Related Degradation Inspection (ARDI) Program to verify that degradation of the components is not occurring. However, the ARDI Program will not necessarily be used for the discovery of crevice corrosion/pitting in the CC relief valves or pumps, as discussed later. The ARDI Program guidelines are outlined in the CCNPP IPA Methodology presented in Section 2.0. of the BGE LRA.

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of adverse examination findings, including consideration of all design loading conditions required by the CLB, and specification of required corrective actions based on the CCNPP Corrective Action Program; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

The CC pumps are inspected for crevice corrosion/pitting using the CCNPP PUMP-14, "Component Cooling Pump Overhaul," procedure. PUMP-14 currently instructs the user to inspect the pump impeller and shaft for erosion, corrosion/pitting, and inspect all pump parts for wear, corrosion, and mechanical damage. The procedure directs the user to contact the System Engineer if any of these indications are found, and replace parts as necessary. [Reference 5] Previous CC pump overhauls at CCNPP did not reveal any problems associated with crevice corrosion/pitting or any other corrosion mechanisms.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Action Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Group 1 (crevice corrosion/pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to corrosion of the CC System device types susceptible to crevice corrosion/pitting:

- The CC device types susceptible to these ARDMs have an intended function that must be maintained under CLB design loading conditions.
- Crevice corrosion/pitting is plausible for the device types discussed in the material and environment section above, which could lead to loss of pressure-retaining boundary integrity.
- The CCNPP CP-206, "Specification and Surveillance CC/SRW System," will mitigate the effects of crevice corrosion/pitting on CC System device types by controlling the range of specific chemical parameters, and provide Action Levels that ensure timely correction of adverse chemistry parameters.
- The CCNPP ARDI Program will assess the potential for crevice corrosion/pitting in the CC System. Appropriate corrective action will be taken if crevice corrosion/pitting is discovered.
- The CCNPP PUMP-14, "Component Cooling Pump Overhaul," requires the inspection of the pump for crevice corrosion/pitting. Any indications of these ARDMs will be reported to the System Engineer and corrective actions taken.

Therefore, there is reasonable assurance that the effects of crevice corrosion/pitting on CC System device types will be managed in order to maintain their intended function under all design loading conditions required by the CLB during the period of extended operation.

Group 2 (erosion corrosion) - Materials and Environment

Table 5.3-3 shows that erosion corrosion is only plausible for the CC System piping. The CC System piping is made from carbon steel that is fabricated into straight sections, bends, and tees. The CC System is chemically treated with hydrazine to lower the dissolved oxygen level. [Reference 1, Pipe-Attachments 4, 5, and 6] The system has a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 2, Section 9.5, Table 9-17]

Group 2 (erosion corrosion) - Aging Mechanism Effects

Carbon steel piping bends, tees, and areas with flow disturbances are especially vulnerable to erosion corrosion. The CC System is treated with hydrazine which scavenges the dissolved oxygen and minimizes the effects of general corrosion. However, the lower oxygen content increases the susceptibility of the piping to the effects of erosion corrosion. The expected effect of erosion corrosion is a general thinning of the material in areas of higher turbulence due to removal of the protective magnetite coating. [Reference 1, Pipe-Attachment 6]

The occurrence of erosion corrosion is highly dependent upon material of construction and the fluid flow conditions. Carbon or low alloy steels are particularly susceptible when in contact with high velocity water (single or two phase) with flow disturbances, low oxygen levels, and a fluid pH < 9.3. Maximum erosion corrosion rates are expected in carbon steel at 130-140°C (single phase) and 180°C (two phase). [Reference 1, Pipe-Attachment 7]

Long-term exposure to erosion corrosion could lead to material loss which, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Therefore, erosion corrosion has been determined to be a plausible ARDM for which aging effects must be managed for the CC System.

Group 2 (erosion corrosion) - Methods to Manage Aging

Mitigation: The effects of erosion corrosion can be mitigated by selecting resistant materials and/or maintaining optimal fluid chemistry conditions. The normal CC System operating temperature is below that expected for maximum erosion corrosion conditions. The low flow velocity in the CC System also minimizes its susceptibility to erosion corrosion.

Discovery: Erosion corrosion can be discovered and monitored by nondestructive examination of potentially affected areas. Inspection of a representative sample of susceptible areas of the system for the signs of erosion corrosion could identify whether this ARDM is a concern in the CC System piping.

Group 2 (erosion corrosion) - Aging Management Program(s)

Mitigation: There are no programs credited with mitigating the effects of erosion corrosion on CC System piping.

Discovery: The CC System piping will be included in the ARDI Program to verify that degradation of this piping is not significant. This program will examine representative piping to determine if the wall thickness will remain sufficient for it to perform its intended function under all CLB conditions. These examinations will be performed prior to the period of extended operation. For further discussion of the ARDI Program, see the Group 1 (crevice corrosion/pitting) discussion for Aging Management Programs under Discovery. [Reference 1, Attachment 1]

During inspection of some open pipe locations it was revealed that a tightly adhering layer of magnetite is present on the inside of the CC piping. Evidence of erosion corrosion was not found during these system lay-up examinations. The evidence of tightly adhering magnetite indicates that the piping has good corrosion resistant characteristics. To date, there have been no indications of erosion corrosion in the CC System.

Group 2 (erosion corrosion)- Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the CC System piping and erosion corrosion:

- The CC System piping provides a pressure-retaining boundary, so its integrity must be maintained under CLB design conditions.

- Erosion corrosion is expected to be minimal, but is considered plausible for the CC System piping; this could result in the loss of component material and lead to the loss of the pressure-retaining boundary.
- The CCNPP ARDI Program will be utilized to examine representative piping and discover any potential erosion corrosion that may occur. Inspections will be performed, and appropriate corrective action will be taken if erosion corrosion is discovered.

Therefore, there is reasonable assurance that the effects of erosion corrosion will be adequately managed to maintain the CC System piping pressure boundary integrity consistent with the CLB during the period of extended operation.

Group 3 (general corrosion) - Materials and Environment

Table 5.3-3 shows that general corrosion is plausible for nine of the CC device types. The CC System device types susceptible to general corrosion, and the material characteristics which are susceptible to this ARDM are listed below: [Reference 1, Attachment 1 and -HB01, CKV01/02, CV01/02/03/05, HV01/02/03/04/05/07, PUMP01, RV102, TI01, TK01 Attachments 4, 5 and 6]

- Piping - carbon steel;
- Check valves - those groups with carbon steel bodies and/or discs;
- Control valves - those groups with carbon steel bodies and cast iron bodies;
- Hand valves - those groups with carbon steel bodies and cast iron bodies;
- Pump - carbon steel casings;
- Relief valves - those groups with carbon steel bodies;
- Temperature element - carbon steel. (TE included in TI device type in Reference 1, Attachment 1);
- Temperature indicator - carbon steel; and
- Tank - carbon steel.

The internal environment of the CC System is chemically-treated water at a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 2, Section 9.5.2.1, Table 9-17] The external environment is ambient atmospheric air inside the Containment and Auxiliary Buildings which is climate controlled. During normal operation the Auxiliary Building, ambient air maximum design relative humidity is 70%, with a maximum design temperature of 160°F (Main Steam Penetration Room). [Reference 6, Attachment 1, Table 1, page 5 of 14]

Group 3 (general corrosion) - Aging Mechanism Effects

Carbon steel and cast iron are susceptible to general corrosion mechanisms in a water environment. General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface by an aggressive environment. The consequences of the damage are the loss of load carrying cross-sectional area of the metal. [Reference 1, Attachment 6s] The ARDM is plausible for the device types discussed in the material and environment section above.

Long-term exposure to an internal chemical environment and potential external corrosive chemical environment may result in general corrosion/area material loss which, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Therefore, general corrosion has been determined to be a plausible ARDM for which aging effects must be managed for the CC System.

Group 3 (general corrosion) - Methods to Manage Aging

Mitigation: The effects of general corrosion can be mitigated on the interior of CC System equipment with chemistry control that monitors pertinent chemical parameters on a frequency that would prevent these parameters from reaching values that could create an environment conducive to general corrosion.

The effects of general corrosion on the CC equipment exterior surfaces can be mitigated through the use of protective coatings and removal of any potentially corrosive materials on component surfaces.

Discovery: Inspecting a representative sample of susceptible areas of the CC System for the signs of general corrosion prior to the period of extended operation can determine whether this ARDM is degrading the intended function of the CC System components. Maintenance/overhaul of CC System components also provides opportunities to inspect for signs of general corrosion.

Group 3 (general corrosion) - Aging Management Program(s)

Mitigation: Procedure CP-206 provides for monitoring of the CC chemistry to control the concentrations of oxygen, chlorides, other chemicals and contaminants. The water is treated with hydrazine to minimize the amount of dissolved oxygen, which aids in minimizing most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal interior piping or component degradation. [Reference 1, Attachment 8]

Discovery: The occurrence of general corrosion is expected to be limited and is not likely to affect the intended function of the system components. The ARDI Program is intended to provide the additional assurance needed to conclude that the effects of plausible aging are being effectively managed for the period of extended operation. The ARDI Program will focus on the effects of plausible ARDMs and the affected components. The results from implementation of the ARDI Program are to be used to determine actions required to ensure that the affected components continue to support the identified passive intended functions throughout the period of extended operation. [Reference 1, Attachment 8] For further details of the ARDI Program, refer to the discussion under Group 1 (crevice corrosion/pitting) - Aging Management Programs.

The CC pumps are inspected for general corrosion using the CCNPP PUMP-14, "Component Cooling Pump Overhaul," procedure. PUMP-14 currently instructs the user to inspect the pump impeller and shaft for erosion, corrosion/pitting, and inspect all pump parts for wear, corrosion, and mechanical damage. The procedure directs the user to contact the System Engineer if any of these indications are found, and replace parts as necessary. [Reference 5]

Group 3 (general corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the general corrosion of CC System equipment:

- The CC System device types subject to this ARDM provide a pressure-retaining boundary function, so their integrity must be maintained under CLB design loading conditions.
- General corrosion is plausible for some of the CC System device types which could lead to material loss and impaired capability of the components to perform their passive intended function of retaining the CC pressure boundary.
- The CCNPP CP-206, "Specification and Surveillance CC/SRW System," is a program that will mitigate the effects of general corrosion on CC System device types by controlling the range of specific chemical parameters, and provides Action Levels that ensure timely correction of adverse chemistry parameters.
- The CCNPP ARDI Program will be utilized to discover general corrosion that may be of concern for the CC System. Inspections will be performed, and appropriate corrective action will be taken if general corrosion is discovered.
- The CCNPP PUMP-14, "Component Cooling Pump Overhaul," requires the inspection of the pump for general corrosion. Any indications of these ARDMs will be reported to the System Engineer and corrective actions taken.

Therefore, there is reasonable assurance that the effects of general corrosion will be adequately managed to maintain the CC System components' pressure boundary integrity intended function consistent with the CLB during the period of extended operation.

Group 4 (rubber degradation) - Materials and Environment

Table 5.3-3 shows that rubber degradation is plausible for the CC containment isolation control valves. These containment isolation control valves have a butyl liner that can degrade with aging. [Reference 1, CV02, Attachment 6] The internal environment of the CC System is chemically-treated water at a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 2, Section 9.5.2.1, Table 9-17]

Group 4 (rubber degradation) - Aging Mechanism Effects

Rubber/elastomers may degrade over time due to the combined effects of scission, crosslinking, and changes associated with compound ingredients. Rubber degradation could result in the loss of leak tightness for the valve. Significant degradation is not expected since rubber/elastomer stressors are minimal in the service environments and appropriate rubber/elastomer selection significantly prolongs service life. However, over time the butyl liners may experience some degradation; therefore, rubber degradation has been determined to be a plausible ARDM for which aging effects must be managed for the susceptible CC device types. [Reference 1, CV02, Attachment 6]

Group 4 (rubber degradation) - Methods to Manage Aging

Mitigation: No programs are credited with mitigating degradation of the control valve liners.

Discovery: Because rubber degradation would affect the leak tightness of these containment isolation valves, local leak rate testing (LLRT) of the containment isolation valves can provide detection of leakage that could be the result of rubber liner degradation. Performing LLRT of these valves on a frequency that could ensure that the valves' intended function is not compromised under the CLB for the period of extended operation could reveal any effects of rubber degradation. [Reference 1, Attachment 8]

Group 4 (rubber degradation) - Aging Management Program(s)

Mitigation: Since there are no reasonable methods of mitigating rubber degradation of the control valves' liner surfaces, there are no programs credited with mitigating the aging effects due to this ARDM.

Discovery: Calvert Cliffs procedures STP M-571E-1, M-571E-2, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64," are part of the overall CCNPP Containment Leakage Rate Program. The CCNPP Containment Leakage Rate Program was established to implement the leakage testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Appendix J specifies containment leakage testing requirements, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. Containment leakage testing requirements include performance of Integrated Leakage Rate Tests, also known as Type A tests, and LLRTs, also known as Type B and C tests. Type A tests measure the overall leakage rate of the containment. Type B tests are intended to detect leakage paths and measure leakage for certain containment penetrations (e.g., airlocks, flanges, and electrical penetrations). Type C tests are intended to measure containment isolation valve leakage rates. [Reference 7, Section 6.5.6; References 8 and 9]

The CCNPP LLRT program is based on the requirements of CCNPP Technical Specifications 3.6.1.2, 4.6.1.2, and 6.5.6. The scope of the program includes Type B and C testing of containment penetrations. The control valves that isolate the containment penetration piping for the CC System are included in the scope of this program as part of the leakage testing for containment penetrations 16 and 18. [References 7, 10, and 11]

The LLRT is performed at a frequency in accordance with 10 CFR 50, Appendix J, Option B. per References 10 and 11, currently the LLRT includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- Test volume is pressurized to at least 53 (+/- 1) psig above atmospheric pressure. Note, the LLRT program test pressure is conservative with respect to the 10 CFR 50, Appendix J test pressure requirements. Appendix J requires testing at a pressure "P_a" which is the peak calculated containment internal pressure related to the Design Basis accident. For CCNPP, P_a, is 49.4 psig as stated in CCNPP Technical Specification 6.5.6.
- Leak rate, pressure, and temperature are monitored at the frequency specified by the LLRT procedure and the results are recorded.

- The maximum indicated leak rate is compared against administrative limits which are more restrictive than the maximum allowable leakage limits.
- “As found” leakage equal to or greater than the administrative limit but less than the maximum allowable limit is evaluated to determine if further testing is required and/or if corrective maintenance is to be performed.
- For “as found” leakage that exceeds the maximum allowable limit, the Shift Supervisor and the Containment System Engineer are notified and they determine if Technical Specification Limiting Condition for Operation (LCO) 3.6.1.2.b has been exceeded. Technical Specification 3.6.1.2.b contains the maximum allowable combined leakage for all penetrations and valves subject to the Type B and C tests. Corrective action is taken as required to restore the leakage rates to within the appropriate acceptance criteria.
- If any maintenance is required on a penetration boundary that could affect the valves’ ability to provide containment integrity, an “as left” test must be performed on the penetration to ensure leakage rates are acceptable.

The corrective actions taken as part of the LLRT program will ensure that the CC System containment isolation control valves remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 4 (rubber degradation) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to CC System containment isolation valve liners subject to rubber degradation:

- The CC System containment isolation control valves provide the containment isolation function and their integrity must be maintained under CLB design conditions.
- Rubber degradation is plausible for the CC System containment isolation control valve liners causing a decrease in leak tightness of the valve seat, which could lead to a loss of containment isolation integrity under CLB conditions.
- The CCNPP LLRT Program performs leakage testing which could detect the effects of rubber degradation on the control valves’ liner (i.e., leak tightness), and contains acceptance criteria that ensure corrective actions will be taken such that there is a reasonable assurance that the containment isolation function will be maintained.

Therefore, there is reasonable assurance that the effects of rubber degradation will be managed in order to maintain the pressure boundary function provided by the CC System control valves, consistent with the CLB during the period of extended operation.

Group 5 (selective leaching) - Materials and Environment

Table 5.3-3 shows that selective leaching is plausible for the CC device types listed. The CC System device types susceptible to selective leaching and the material characteristics which are susceptible to this ARDM are listed below: [Reference 1, Attachment 1, and AVV01, CV01/02/05, HV04/05, RV03, SV01 Attachments 4, 5, and 6]

- Automatic vents - cast brass base and shell;
- Control valves - some groups have cast iron bodies, and some have aluminum bronze discs;
- Hand valves - some groups have cast iron valve bodies/bonnets and/or cast iron discs;
- Relief valves - some groups have brass seats and discs; and
- Solenoid valves - are made of brass.

The internal environment of the CC System is chemically-treated water at a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 2, Section 9.5.2.1, Table 9-17] This CC water is treated with hydrazine to lower the dissolved oxygen level. [Reference 1, Pipe-Attachment 6] Certain regions of the CC System have low or stagnant flow conditions.

Group 5 (selective leaching) - Aging Mechanism Effects

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The most common example is the selective removal of zinc in brass alloys (dezincification). Similar processes occur in other alloy systems in which aluminum, iron, cobalt, chromium and other elements are removed. There are two types of selective leaching, layer-type and plug-type. Layer-type is a uniform attack whereas plug-type is extremely localized leading to pitting. Overall dimensions do not change appreciably. If a piece of equipment is covered by debris or surface deposits and/or not inspected closely, sudden unexpected failure may occur due to the poor strength of the remaining material. Selective leaching requires susceptible materials and a corrosive environment. Conducive environmental conditions include high temperature, stagnant aqueous solution, and porous inorganic scale. Acidic solutions and oxygen may aggravate the mechanism. [Reference 1, Valve Attachment 7]

The device types discussed in the materials and environment section above are susceptible to the ARDM (for the valve body, the liner is not credited with aging management; it is conservatively assumed that the material is in contact with the fluid due to degradation of the rubber liner). The device types are exposed to flow conditions and may be exposed to stagnant conditions. The expected effects of selective leaching are cracking and dezincification. [Reference 1, CV Attachment 6, SV Attachment 6]

Gray cast irons are susceptible to a selective leaching process called "graphitic corrosion." The iron or steel matrix leaches from the material leaving a porous mass consisting of a graphite network, voids and rust. The cast iron loses strength and its metallic properties. [Reference 1, Valve Attachment 7]

Long-term exposure to the chemical environment in the CC System may result in selective leaching and, if unmanaged, could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. Therefore, selective leaching has been determined to be a plausible ARDM for which aging effects must be managed for the CC System.

Group 5 (selective leaching) - Methods to Manage Aging

Mitigation: Maintaining a CC System environment of purified water with controls on pH, suspended solids and chlorides during normal plant operation can mitigate this ARDM. The addition of hydrazine lowers the CC System dissolved oxygen level and mitigates one of the aggravating chemical factors. [Reference 1, Attachments 6 and 8]

Discovery: Inclusion of CC System device types in an inspection program that examines a representative sample of susceptible areas of the system for the signs of selective leaching prior to the period of extended operation could identify whether this ARDM is actually occurring in the CC device types.

Group 5 (selective leaching) - Aging Management Program(s)

Mitigation: The CCNPP CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," provides for monitoring of the CC chemistry to control the concentrations of oxygen, chlorides, other chemicals and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 1, Attachment 8] Refer to the discussion of CP-206 under Group 1 (crevice corrosion/pitting), Aging Management Programs.

Discovery: The CC System device types listed above will be included in the ARDI Program to verify that degradation of CC device types is not excessive. Refer to the ARDI discussion under Group 1 (crevice corrosion/pitting), Aging Management Programs for more details on this program. [Reference 1]

Group 5 (selective leaching) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to selective leaching for the CC device types listed here:

- The control valves, hand valves, relief valves and solenoid valves described here act as a pressure-retaining boundary, and their integrity must be maintained under CLB design conditions.
- Selective leaching is plausible for the valve device types discussed in the materials and environment section above, which could lead to the loss of the pressure-retaining boundary function of the CC System.
- The CCNPP CP-206, "Specification and Surveillance CC/SRW Systems," is a program that will mitigate the effects of aging mechanisms on CC System device types by controlling the range of specific chemical parameters and providing action levels for these chemistry parameters.
- The CCNPP ARDI Program will be utilized to discover any selective leaching that may be of concern for the CC System device types. Inspections will be performed, and appropriate corrective action will be taken if selective leaching is discovered.

Therefore, there is a reasonable assurance that the effects of selective leaching will be managed in order to maintain the CC components intended function under all design loading conditions required by the CLB during the period of extended operation.

Group 6 (wear) - Materials and Environment

Table 5.3-3 shows that wear is plausible for the CC device types listed. The CC System device types susceptible to wear and the material characteristics which are susceptible to this ARDM are listed below: [Reference 1, Attachment 1, and CKV 02, CV02, RV01, RV02, RV03, Attachments 4, 5, and 6]

- Check valves - some groups have carbon steel discs;
- Control valves - some groups have butyl valve liners; and
- Relief valves - some groups have stainless steel valve seats and discs, and some have brass valve seats and discs.

The internal environment of the CC System is chemically-treated water at a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 2, Section 9.5.2.1, Table 9-17] During normal plant operation valves are actuated to move between the closed, intermediate, and full open position. Some valves may remain in the open or closed position for an extended period of time before being actuated to a different position.

Group 6 (wear) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear) or sliding motions under the influence of a corrosive environment (fretting). In addition to material loss from the above wear mechanisms, impeded relative motion between two surfaces held in intimate contact for extended periods may result in galling/self welding. Motions may be linear, circular, or vibratory in inert or corrosive environments. The most common result of wear is damage to one or both surfaces involved in the contact. Wear most typically occurs in components which experience considerable relative motion such as valves and pumps, in components which are held under high loads with no motion for long periods (valves, flanges), or in clamped joints where relative motion is not intended but occurs due to a loss of clamping force (e.g., tubes in supports, valve stems in seats, springs against tubes). Wear rates may increase as worn surfaces experience higher contact stresses. [Reference 1, Valve, Attachment 7]

The sub-components of the device types are located in the CC fluid flow stream. Movement of the sub-component is expected to occur during changes and variations in flow conditions. Valve discs may periodically relieve pressure and experience movement against the seat. The expected effect of wear is a progressive loss of material from the sub-component. Limited leakage past the check valve discs will not significantly impact intended function. The CC device types listed above are therefore susceptible to this ARDM. [Reference 1, CKV, CV, RV, Attachment 6]

Group 6 (wear) - Methods to Manage Aging

Mitigation: Since the wear of the valves seating surfaces is due to valve operation, decreased use of the valve would slow the degradation of the valve leak tightness. However, this method is not feasible from a plant operations standpoint. Therefore, it is concluded that there are no reasonable methods of mitigating wear of the valves seating surfaces.

Discovery: Wear can be discovered by inspecting and testing the valve device types that are susceptible to this ARDM. Routine bench testing and inspection can identify wear of the relief valve seating surfaces. Inspections are to be performed on representative samples of susceptible areas of the CC System for the signs of wear prior to the period of extended operation. In addition, LLRT of the containment isolation valves can provide detection of leakage that could be the result of wear on valve internals. The frequency of LLRT of these valves is sufficient to ensure that the intended function is not compromised under the CLB for the period of extended operation.

Inclusion of CC System device types in an inspection program that examines a representative sample of susceptible areas of the system for the signs of wear prior to the period of extended operation could identify whether this ARDM is actually occurring on the CC device types.

Group 6 (wear) - Aging Management Program(s)

Mitigation: Since wear cannot be avoided during plant operation, there are no programs credited with mitigating wear.

Discovery: The CCNPP Procedures STP M-571E-1, M-571E-2, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64," are part of the overall CCNPP Containment Leakage Rate Program that will be used to monitor the CC containment isolation control valves for leak tightness. The CCNPP Containment Leakage Rate Program was established to implement the leakage testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Appendix J specifies containment leakage testing requirements, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. Containment leakage testing requirements include performance of Integrated Leakage Rate Tests, also known as Type A tests, and LLRTs, also known as Type B and C tests. Type C tests are intended to measure containment isolation valve leakage rates. [Reference 7, Section 6.5.6; References 8 and 9] For further discussion of the LLRT program as it relates to the CC containment isolation control valves, refer to the Group 4 (rubber degradation) section - Aging Management Programs.

The CC check valves will be included in the ARDI Program to verify that wear is not occurring. Refer to the ARDI discussion under Group 1(crevice corrosion/pitting) - Aging Management Programs for more details of the program.

Calvert Cliffs checklists MPM01012, MPM01013, and MPM01143, "Relief Valves," direct the removal, testing, and reinstallation of the satisfactorily tested relief valves. The checklists refer to another procedure for the performance of the relief valve setpoint test, and are performed on a four- to five-year frequency. [References 12, 13, and 14] Routine bench testing will identify wear of the valve seating surfaces. [Reference 1, Attachment 8]

Group 6 (wear)- Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the CC device types subject to wear:

- The CC device types described here act as a pressure-retaining boundary, and their integrity must be maintained under CLB design conditions.
- Wear is plausible for the valve device types discussed in the materials and environment section above which could lead to the loss of the pressure-retaining boundary function of the CC System.
- The CCNPP LLRT Program provides leakage testing which could detect the effects of wear on the CC control valves listed for this ARDM, and contains acceptance criteria that ensure corrective actions will be taken such that there is a reasonable assurance that the pressure boundary function will be maintained.
- The CCNPP ARDI Program will be utilized to discover any wear that may be of concern for the CC System check valves. Inspections will be performed, and appropriate corrective action will be taken if significant wear is discovered.
- The CCNPP MPM01012, MPM01013, and MPM01143 Checklists direct the removal, relief setpoint testing, and reinstallation of CC System relief valves. Routine bench testing will identify wear of the valve seating surface.

Therefore, there is a reasonable assurance that the effects of wear will be managed in order to maintain the CC device types' intended function under all design loading conditions required by the CLB during the period of extended operation.

5.3.3 Conclusion

The aging management programs discussed for the CC System are listed in Table 5.3-4. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the CC System components will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, " Corrective Actions Program." Procedure QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 5.3-4

LIST OF AGING MANAGEMENT PROGRAMS FOR THE COMPONENT COOLING SYSTEM

	Program	Credited For
Existing	CCNPP "Specifications and Surveillance for CC/SRW Systems," CP-206	Mitigation of the effects of crevice corrosion/pitting (Group 1), general corrosion (Group 3), and selective leaching (Group 5) of CC System components.
Existing	CCNPP "Component Cooling Pump Overhaul and Inspection," PUMP-14	Discovery and management of crevice corrosion/pitting (Group 1) and general corrosion (Group 3) of the CC pumps through inspection and overhaul. These activities are performed as required based on pump performance trends or corrective action requirements.
Existing	LLRTs, STP M-571E-1 and M-571E-2	Discovery of leakage that could be the result of rubber liner degradation (Group 4) or wear (Group 6) of the CC System containment isolation control valve internals.
Existing	CCNPP Preventive Maintenance Checklists MPM01012, MPM01013, MPM01143	Discovery and management of wear (Group 6) of the CC System relief valves. They are performed on a four- to five-year interval to remove and test CC System relief valves.
New	ARDI Program	Discovery and management of the effects of crevice corrosion/pitting (Group 1), erosion corrosion (Group 2), general corrosion (Group 3), selective leaching (Group 5), and wear (Group 6) for CC System components. The results from implementation of the ARDI Program are to be used to determine actions required to ensure that the affected components continue to support the identified passive intended functions throughout the period of extended operation.

5.3. References

1. CCNPP "Component Cooling System Aging Management Review," Revision 2, June 29, 1997
2. CCNPP, Updated Final Safety Analysis Report, Revision 19
3. CCNPP Technical Procedure Component Level ITLR Screening Results, Component Cooling System, Revision 1, August 15, 1996
4. CCNPP CP-206, "Specifications and Surveillance Component Cooling/Service Water System," Revision 3, November 4, 1996
5. CCNPP PUMP-14, "Component Cooling Pump Overhaul," Revision 1, February 4, 1997
6. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions," Revision 0, November 8, 1995
7. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), "Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit 1(TAC No. M92549) and Unit 2 (TAC No. M92550)," dated October 18, 1996 [Amendment Nos. 217/194]
8. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."
9. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated January 16, 1996, "License Amendment Request: Adoption of 10 CFR Part 50, Appendix J, Option B for Type A Testing"
10. CCNPP Surveillance Test Procedure STP-M-571E-1, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64" (Unit 1), Revision 0, May 17, 1991
11. CCNPP Surveillance Test Procedure STP-M-571E-2, "Local Leak Rate Test, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64" (Unit 2), Revision 0, October 17, 1991
12. CCNPP MPM01012 Checklist Sheet, "Remove Relief Valves," Revision 0, January 27, 1992
13. CCNPP MPM01013 Checklist Sheet, "Remove Relief Valves," Revision 0, January 28, 1992
14. CCNPP MPM01143 Checklist Sheet, "Remove Relief Valves," Revision 0, December 24, 1991

5.4 Compressed Air System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Compressed Air System. The Compressed Air System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.4.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.4.1.1 presents the results of the system level scoping, 5.4.1.2 the results of the component level scoping, and 5.4.1.3 the results of scoping to determine components subject to an AMR.

Representative historical operating experience pertinent to aging is included in appropriate areas to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

5.4.1.1 System Level Scoping

This section begins with a description of the system which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description/Conceptual Boundaries

The Compressed Air System consists of an Instrument Air (IA), Plant Air (PA), and Saltwater Air Subsystem for each unit. The IA Subsystem is designed to provide a reliable supply of dry and oil-free air for the pneumatic instruments and controls and pneumatically-operated containment isolation valves. The PA Subsystem is designed to meet necessary service air requirements for plant maintenance and operation. The Saltwater Air Subsystem provides a backup supply of compressed air to most safety-related (SR) components. [Reference 1, Sections 9.10.2 and 9.10.5]

The IA Subsystem incorporates two non-safety-related (NSR), full-capacity, oil-free compressors, each having a separate inlet filter, aftercooler and moisture separator. The IA compressors discharge to a single header which is connected to two air receivers. Both air receivers discharge to a compressed air outlet header which supplies IA to the air dryers and filter assembly. The compressed air header then divides into branch lines supplying compressed air to the pretreatment and tank storage area, the intake structure, the service building, the water treatment area, the Turbine Building, the Containment Structure, and the Auxiliary Building. [Reference 1, Section 9.10.2]

An emergency back-up tie from the PA header automatically supplies air to the IA Subsystem if the pressure at the instrument filter and dryer assembly falls below a set value. The PA service header isolation valves also shut if the pressure falls below a set value so the PA compressors discharge only to the IA Subsystem. [Reference 1, Section 9.10.2; References 2 and 3]

The PA Subsystem consists of one NSR, full-capacity PA compressor with an inlet filter, aftercooler, and moisture separator which discharges to the PA receiver. The receiver outlet header is connected to the prefilter assembly, which is followed by an outlet header. The outlet header branches into two separate air headers, one that supplies the IA dryers and filter assembly through a cross connect that is normally isolated, and the other that supplies the PA Subsystem loads: the pretreatment and storage tank area; the intake structure; the service building; the water treatment area; the Turbine Building, The Containment Structure; and the Auxiliary Building. A system cross-tie between Unit 1 and Unit 2 PA Subsystems has been provided for the PA headers. [Reference 1, Section 9.10.2]

A continuous supply of IA is provided to hold various pneumatically-operated valve actuators in the positions necessary for plant operating conditions. Under normal plant operating conditions, one IA compressor operates and the second IA compressor is on automatic standby. [Reference 1, Section 9.10.4] The PA Subsystem is normally cross-connected between units, with one PA compressor operating and supplying both units' loads, and the other compressor in standby. The power supply for the compressors is the normal distribution system and can be backed up by the diesel generators. Accumulators are located at various locations throughout the plant and act as system reservoirs and also reduce system pressure pulsations. [Reference 4, Section 1.1.2]

In the event that IA and PA compressors become unavailable, such as following load shedding due to a safety injection actuation signal, two SR saltwater air compressors will provide a backup supply of compressed air to most SR components. These compressors are automatically started upon receipt of a safety injection actuation signal and can also be operated from a local panel. The saltwater air compressors supply the saltwater air header which distributes air to all saltwater isolation valves for the service water heat exchangers, component cooling heat exchangers, and the Emergency Core Cooling System pump room air coolers. The saltwater air header also supplies compressed air to the auxiliary feedwater control valves, containment air-operated control valves, atmospheric dump valves, reactor coolant sample isolation valves, and service water containment air cooler valves. [References 1, 5, 6, 7, 8, 9, 10, and 11]

System Interfaces

The Compressed Air System has an interface with the Service Water System which provides cooling water to the IA and PA air compressors and aftercoolers. The Service Water System is within the scope of license renewal and is addressed in Section 5.17 of the BGE LRA. The Compressed Air System also has interfaces with the many systems which have components being supplied with compressed air. Any local air set or accumulator associated with a specific load is typically included within the boundaries of the system being supplied.

System Scoping Results

The Compressed Air System is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of the Compressed Air System were determined based on the requirements of §54.4(a)(1) and (2), in accordance with the CCNPP IPA Methodology, Section 4.1.1: [Reference 12, Table 1]

- Provide a vital auxiliary air supply, via Saltwater Air Subsystem, for components used to mitigate Design Basis Events.
- Provide a vital auxiliary air supply, via Auxiliary Feedwater Air Subsystem, for components used to mitigate Design Basis Events.
- Provide a vital auxiliary air supply, via Containment Air Subsystem, for components used to mitigate Design Basis Events.
- Provide a load shed indication.
- Provide Containment Isolation during a Design Basis Event.
- Maintain the pressure boundary of the system (liquid and/or gas).
- Maintain electrical continuity and/or provide protection of the electrical system.
- Provide seismic integrity and/or protection of SR components.

The following Compressed Air System intended functions were determined based on the requirements of §54.4(a)(3): [Reference 12, Table 1]

- For fire protection (§50.48) - Provide control air to essential loads to ensure safe shutdown in the event of a postulated severe fire.
- For environmental qualification (§50.49) - Maintain functionality of electrical equipment as addressed by the Environmental Qualification Program, and provide information used to assess the plant and environs condition during and following an accident.

All components of the Compressed Air System that meet the environmental qualification criteria of 54.4(a)(3) are also SR. Some of the components which meet the fire protection criteria (§50.48) are NSR, and are in the scope of license renewal only because of the 54.4(a)(3) criteria.

All components of the Compressed Air System that support the above functions, with the exception of the fire protection function, are SR and Seismic Category 1 and are subject to the applicable loading conditions identified in the UFSAR Section 5A.3.2 for Seismic Category 1 systems and equipment design. Portions of the system required for fire protection are NSR and non-seismic. [References 1, 13, and 14]

The compressed air piping is designed in accordance with ANSI B31.1, Power Piping Code, with the exception of the containment penetration piping sections. The IA and PA containment penetration piping is designed to Class II of ANSI B31.7, Nuclear Power Piping Code. The piping is considered Non-Class piping for the purposes of the American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection Program, with the exception of the containment penetration piping sections. The IA containment penetration piping section is considered Class MC for inservice inspection. The PA containment penetration piping has both Class MC and Non-Class designations. [References 5, 6, 7, 8, 9, 15, 16, and 17]

Operating Experience

In 1988, the NRC and the Institute of Nuclear Power Operations (INPO) notified utilities of concerns regarding failures of plant IA systems. NRC's Generic Letter 88-14 required each licensee to perform a design and operational verification of the IA system. Institute of Nuclear Power Operations' Significant Operating Experience Report 88-1 included a number of recommendations related to operations, training, maintenance, and design/analysis of IA systems. Baltimore Gas and Electric Company initiated a number of actions, including testing of air-operated valves and dampers supplied by SR accumulators, in response to these notices. A review of the Compressed Air System, including a root cause analysis, identified inadequacies in design, maintenance, and testing practices. Due to corrective actions resulting from this review, the Compressed Air System has undergone significant improvements in the areas of design, maintenance, operations, and testing. [References 18, 19, 20, 21, and 22]

Since these improvements, the Compressed Air System equipment has been well maintained and the air quality is periodically tested and maintained in accordance with standard ISA-S-7.3, "Quality Standard for Instrument Air." Operating experience has shown that the air normally provided is very dry and contains little particulate matter. Dewpoint temperature, which is indicative of moisture content, is typically less than -40ºF at 100 psig, which is well below the requirement; i.e., at least 18ºF below the minimum local recorded ambient temperature at the plant site. Particulate sampling shows a relatively normal distribution of particle sizes for a filtered Compressed Air System. The little amount of particulate measured which exceeds specific component maximum particulate requirements is captured in local filters at those components. No trace of oil or hydrocarbons has been detected, so oil content is no longer routinely monitored. The normal supply of air is from the IA compressors which are of oil-free design. [Reference 23]

5.4.1.2 Component Level Scoping

Based on the intended system functions listed above, the portion of the Compressed Air System that is within the scope of license renewal includes all SR components in the system (electrical, mechanical, and instrument), and their supports. Safety related portions of the Compressed Air System include those that support the intended functions listed above in System Scoping Results for meeting the requirements of §54.4(a)(1) and (2), and the environmental qualification (§50.49) intended function under the requirements of §54.4(a)(3). [Reference 12, Table 1; Reference 13]

Also within the scope of license renewal are certain NSR portions of the Compressed Air System required for fire protection (§50.48) under the requirements of §54.4(a)(3). Included are those portions of the system that supply air to components required to achieve safe shutdown in the event of a severe fire, as required by 10 CFR Part 50 Appendix R. Each of the Compressed Air System air compressors, i.e., IA, PA and saltwater air compressors, support the fire protection intended function because they are relied on in postulated fire scenarios. Essential safe shutdown loads, which may be supplied with compressed air from either SR or NSR portions of the system in the event of a fire, include service water valves, main steam isolation valves, emergency diesel generators, saltwater valves, component cooling valves, safety injection valves, and containment spray valves. However, as discussed below, all of the NSR portions of the Compressed Air System subject to AMR are evaluated in the Fire Protection AMR presented in Section 5.10 of the BGE LRA. [References 13 and 14]

The following 27 device types in the Compressed Air System were designated as within the scope of license renewal because they have at least 1 intended function [Reference 4, Section 3.2 and Table 3-2]:

- Air Accumulator
- Air Compressor
- Check Valve
- Coil
- Compressed Air System Piping
- Control Valve
- Drain Trap
- Filter
- Fuse
- Handswitch
- Hand Valve
- Level Switch
- Motor (SR saltwater air compressors)
- Motor (NSR IA and PA air compressors)
- Motor-Operated Valve (MOV)
- Panel
- Position Indicating Lamp
- Position Switch
- Power Lamp Indicator
- Pressure Control Valves (PCVs)
- Pressure Indicator
- Pressure Switch
- Pump (air amplifier)
- Relay
- Relief Valve
- Solenoid Valve
- Temperature Switch

Some components in the Compressed Air System are common to many other plant systems and have been included in separate commodity AMRs which address those components for the entire plant. These components include the following: [Reference 4, Section 3.2]

- Structural supports for piping, cables, and components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA.
- Electrical instrumentation, control, and power cabling are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the passive intended function entitled "maintain electrical continuity and/or provide protection of the electrical system" for the Compressed Air System.
- Instrument tubing and piping and the associated supports, instrument valves, and fittings (generally everything from the outlet of the final root valve up to and including the instrument), and the pressure boundaries of the instruments themselves, are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.
- All tubing and many PCVs, regulating valves, and reducing valves do not have unique equipment identifiers in the CCNPP Master Equipment List. These valves are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

5.4.1.3 Components Subject to AMR

This section describes the components within the Compressed Air System which are subject to AMR. It begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following Compressed Air System functions were determined to be passive. [Reference 4, Table 3-1]

- Maintain the pressure boundary of the system.
- Maintain electrical continuity and/or provide protection of the electrical system.
- Provide seismic integrity and/or protection of SR components.

The Compressed Air System has an additional function associated with fire protection. Both SR and NSR components support the fire protection function of providing control air to essential loads to ensure safe shutdown in the event of a postulated severe fire. Only the SR Compressed Air System components, as defined in the CCNPP Engineering Standard for Functional Safety Classifications, Reference 13, are further evaluated in this section. In accordance with the CCNPP IPA Methodology, NSR portions of the Compressed Air System, which are within the scope of license renewal only for their fire protection functions, are evaluated in the fire protection commodity evaluation described in Section 5.10 of the BGE LRA. [Reference 14]

Device Types Subject to AMR

Of the 27 device types within the scope of license renewal: [Reference 4, Table 3-2; References 14 and 24]

- Nine device types have only active functions and do not require AMR; Coil, Fuse, Hand Switch, Motor (SR saltwater air compressors), Motor (NSR IA and PA compressors), Position Indicating Lamp, Position Switch, Power Lamp Indicator, and Relay.
- One device type is comprised of components subject to a replacement program, i.e., environmental qualification program, and does not require AMR; Solenoid Valve.
- Three devices types are evaluated in another section of the BGE LRA.
- Panel is evaluated for the effects of aging in the Electrical Panels Commodity Evaluation in Section 6.2 of the BGE LRA. This commodity evaluation completely addresses the passive intended function entitled "provide seismic integrity and/or protection of SR components."
- Pressure Indicator and Pressure Switch are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.
- Four device types do not require AMR because of specific exclusion by the license renewal rule, i.e., all components included with the skid-mounted saltwater air compressors; Air Compressor (including associated accumulator), Drain Trap, Level Switch, and Temperature Switch.

The remaining ten device types listed in Table 5.4-1 are subject to AMR and are included in this section. Maintenance of the pressure boundary of the system is the only passive intended function associated with the Compressed Air System that is not addressed by one of the commodity evaluations referred to above. Therefore, only the pressure retaining function for the ten device types listed in Table 5.4-1 is considered in the AMR for the Compressed Air System. Unless otherwise annotated, all components of each listed device type are subject to AMR.

TABLE 5.4-1
COMPRESSED AIR SYSTEM DEVICE TYPES REQUIRING AMR

Air Accumulator (1)
Compressed Air System Piping (3)
Check Valve
Control Valve
Filter
Hand Valve(2)
MOV
PCV (1 and 4)
Pump (air amplifier)
Relief Valve (1)

(1) Excludes SR components that are integral to the skid-mounted saltwater air compressors.

(2) Instrument line manual drain, equalization, and isolation valves in the Compressed Air System that are subject to AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. Instrument line manual root valves are evaluated in this report. [Reference 24, Attachment 3]

(3) All tubing and tubing supports are included in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

(4) Many PCVs, regulating valves, or reducing valves do not have unique equipment identifiers in the CCNPP Master Equipment List. These valves are included in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

5.4.2 Aging Management

A list of potential age-related degradation mechanisms (ARDMs) identified for the Compressed Air System components is given in Table 5.4-2. [Reference 4, Table 4-2] The plausible ARDMs are identified in the Table by a check mark (✓) in the appropriate device type column. For AMR, some device types have a number of groups associated with them because of the diversity of material used in their fabrication or differences in the environments to which they are subjected. A check mark indicates that the ARDM applies to at least one group for the device type listed. For efficiency in presenting the results of the evaluations in this section, ARDM/device type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components within that group. Exceptions are noted in the discussions, where appropriate. Table 5.4-2 identifies the group in which each ARDM/device type combination belongs. The following groups have been selected for the Compressed Air System.

Group 1 - Includes wear for all check valves and MOVs subject to AMR.

Group 2 - Includes general corrosion for all of the components subject to AMR except for the pump (air amplifier).

TABLE 5.4-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE COMPRESSED AIR SYSTEM

Potential ARDMs	**Compressed Air System Device Types**									
	HB	ACC	CKV	PUMP(a)	CV	FL	HV	MOV	PCV	RV
Fatigue										
Fouling										
General Corrosion	✓(2)	✓(2)	✓(2)		✓(2)	✓(2)	✓(2)	✓(2)	✓(2)	✓(2)
Hydrogen Damage										
Radiation Damage										
Rubber Degradation										
Wear			✓(1)					✓(1)		

✓ - Indicates that the ARDM is plausible for component(s) within the Device Type
(#) - Indicates the Group in which this ARDM/device type combination is evaluated
(a) - Air amplifier

Device Types					
HB	=	Compressed Air, System Piping	FL	=	Filter
ACC	=	Air Accumulator	HV	=	Hand Valve
CKV	=	Check Valve	MOV	=	Motor-Operated Valve
PUMP	=	Pump	PCV	=	Pressure Control Valves
CV	=	Control Valve	RV	=	Relief Valve

Note: Not every group within the device types listed here may be susceptible to a given ARDM. This is because groups within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

Note: Fouling of Compressed Air System components is inconsequential because of existing air quality requirements that are maintained by system air dryers and filters. If fouling were to occur, it would affect an active function, which would be detectable during plant operation and corrected through on-going maintenance program activities.

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods to manage aging, aging management program(s), and aging management demonstration.

Group 1 (wear for check valves and MOVs) - Materials and Environment

The Compressed Air System check valves, for which wear is considered a plausible degradation mechanism, include one valve per unit which forms part of the containment isolation pressure boundary. Also included are four valves per unit that form a SR-to-NSR pressure boundary for portions of the system. Each of those valves must close in order to maintain the required pressure boundary. Other Compressed Air System check valves are not relied on to shut in order to maintain the intended functions. The subject check valves are divided into sub-components of body/bonnet and disk/seat. The body/bonnet are constructed from carbon steel and the disk/seat from either carbon steel or stainless steel. [Reference 4, Attachment 4, Attachment 5 for Check Valves, and Attachment 8]

The Compressed Air System MOVs serve as containment isolation pressure boundary and are divided into the subcomponents of body/bonnet and internals. The body/bonnet are constructed from carbon steel and the internals are constructed from alloy steel. [Reference 4, Attachment 4 for MOVs, and Attachment 8]

The internal environment for the Compressed Air System components is normally compressed air supplied by the IA compressors. The IA is very dry, filtered, and oil-free air. Particle size, dew point, and oil hydrocarbons are controlled for the IA supply in accordance with standard ISA-S-7.3, "Quality Standard for Instrument Air." The dew point, which is a measurement of air moisture content, is normally maintained at -40°F at 100 psig. This dew point is well below the air quality standard of at least 18°F below the minimum local recorded ambient temperature at the plant site. [References 1 and 23]

Occasionally, air from either the PA or saltwater air compressors may enter the system. That is because the PA or saltwater air compressors can be used as a backup to the IA compressors if they become unavailable. Additionally, the saltwater air compressors are run for brief periods of time each month for testing. [References 5, 6, 8, 9, and 25] If the PA or saltwater air compressors are used to supply the IA Subsystem, the return to use of the IA compressors as the supply of compressed air will rapidly return the air quality to the normally dry state. This is due to the very dry air supplied by the IA compressors, and because the continuous air demand continuously purges the IA Subsystem lines.

The PA Subsystem air compressors use a filter-silencer which removes particulates in the air. The PA compressor discharges to an aftercooler and moisture separator which removes moisture in the air. Furthermore, the PA Subsystem utilizes a prefilter between the receivers and the headers. This prefilter removes oil and moisture from the air to prevent contamination of the Compressed Air System components and loads. The saltwater air compressors are designed to prevent oil or oil vapor from being compressed with the air. An aftercooler cools the compressed air and condenses moisture, which passes to the receiver where it is drained by an automatic valve. Based on the design and limited operation of these backup systems, perturbations in air quality outside of accepted industry air quality standards (dry, filtered, and oil-free) will be limited. [References 5, 6, 8, and 9]

Group 1 (wear for check valves and MOVs) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear) or fluid stream (erosion); and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Motions may be linear, circular, or vibratory in inert or corrosive environments. In addition to material loss from the above wear mechanisms, impeded relative motion between two surfaces held in intimate contact for extended periods may result in galling/self welding. Wear rates may accelerate as expanded clearances result in higher contact stresses. [Reference 4, Attachment 7 for Valves]

The disk/seat of check valves subject to wear are required to close to maintain containment pressure boundary integrity or system pressure boundary integrity. Wear of other Compressed Air System check valves was not considered because these components are not required to close to maintain intended functions and are, therefore, not subject to AMR. [Reference 4, Attachment 4s and 5s for Check Valves]

Wear is considered plausible for the disk/seat of check valves and MOVs because they may experience cyclic relative motion at the tight fitting surfaces. Movement of the disk against the seat can result in a gradual loss of material, which could result in a small amount of leakage. If left unmanaged, wear could eventually lead to a loss of pressure boundary integrity. [Reference 4, Attachment 4s, 5s, and 6s] Calvert Cliffs has experienced some wear of check valves with several valves failing back-leakage tests, including those performed in response to Generic Letter 88-14. However the root cause of these failures is due to a combination of wear and the valve being inappropriately chosen for its intended application. [Reference 23]

Group 1 (wear for check valves and MOVs) - Methods to Manage Aging Effects

Mitigation: Since the wear of check valve disk/seats and MOV internals are due to valve operation, decreased operation of the valves would slow the degradation of the valves seating surfaces. This mitigation technique is not feasible, however. The discovery methods discussed below are deemed adequate for mitigating wear of check valve disk/seats and MOV internals. It should be noted that galling/self-welding occur when there is impacted relative motion between two surfaces held in intimate contact for extended periods. Periodic valve operation actually minimizes this phenomenon.

Discovery: Wear for check valve disks/seats and MOV internals can be detected by performing leak rate testing. Since wear occurs gradually over time, periodic testing can be used to discover minor leakage so that corrective actions can be taken prior to the loss of an intended function. [Reference 4, Attachment 6s for Check Valves and MOVs]

Group 1 (wear for check valves and MOVs) - Aging Management Program(s)

Mitigation: There are no feasible methods of mitigating wear of the check valve disk/seat and MOV internals; therefore, there are no programs credited with mitigating the aging effects due to this ARDM.

Discovery: The check valves and MOVs performing the containment isolation function are subject to local leak rate testing under the CCNPP Containment Leakage Rate Program, as required by 10 CFR Part 50, Appendix J. [Reference 4, Attachment 6 for Check Valves and MOVs] The check valves providing a SR-NSR pressure boundary for portions of the system are subject to leak rate testing under the CCNPP Pump and Valve Inservice Testing (IST) Program. This valve testing was voluntarily added to the IST Program that is used to meet the requirements of 10 CFR 50.55a(f). Both programs are implemented in accordance with the plant Technical Specifications. [References 26; 27; 28, Section 1; and Reference 29]

Operating experience relative to the IST on IA check valves and MOVs includes isolated cases of unacceptable leakage. Some of these experiences were identified in testing implemented in response to NRC and industry concerns regarding check valves in general. The root cause of these problems has been attributed to a combination of wear, small amounts of debris, and the valve being inappropriately chosen for its intended application. No widespread problems associated with wear of the check valves or MOVs have been identified. [References 18 and 22]

CCNPP Containment Leakage Rate Testing Program

The local leak rate test (LLRT) is performed under Surveillance Test Procedures M-571F-1 and M-571F-2 as part of the overall CCNPP Containment Leakage Rate Testing Program. The CCNPP Containment Leakage Rate Testing Program was established to implement the leakage testing of the containment, as required by 10 CFR 50.54(o) and 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors - Option B." Appendix J specifies containment leakage testing requirements, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. Containment leakage testing requirements include performance of Integrated Leakage Rate Tests, also known as Type A tests, and LLRTs, also known as Type B and C tests. Type A tests measure the overall leakage rate of the containment. Type B tests are intended to detect leakage paths and measure leakage for certain containment penetrations (e.g., airlocks, flanges, and electrical penetrations). Type C tests are intended to measure containment isolation valve leakage rates. [Reference 26, Section 6.5.6; References 30 and Reference 31]

The CCNPP Containment Leakage Rate Testing Program is based on 10 CFR Part 50, Appendix J, Option B, requirements and implements the requirements in CCNPP Technical Specifications 3.6.1.2, 4.6.1.2, and 6.5.6. The scope of the program includes Type B and C testing of containment penetrations [References 26, 27, and 28] Per References 27 and 28, currently the LLRT includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- Test volume is pressurized to at least 53 ± 1 psig above atmospheric pressure, which is conservative with respect to the 10 CFR Part 50, Appendix J, test pressure requirements.
- Leak rate, pressure, and temperature are monitored at the frequency specified by the LLRT procedure and the results are recorded.
- The maximum indicated leak rate is compared against administrative limits, which are more restrictive than the maximum allowable leakage limits.
- "As found" leakage equal to or greater than the administrative limit, but less than the maximum allowable limit, is evaluated to determine if further testing is required and/or if corrective maintenance is to be performed.
- For "as found" leakage that exceeds the maximum allowable limit, the Shift Supervisor and the Containment System Engineer are notified, and they determine if Technical Specification Limiting Condition for Operation (LCO) 3.6.1.2.b has been exceeded. Technical Specification 3.6.1.2.b contains the maximum allowable combined leakage for all penetrations and valves subject to the Type B and C tests. Corrective action is taken as required to restore the leakage rates to within the appropriate acceptance criteria.

- If any maintenance is required on a penetration boundary that would affect the valves' ability to perform their closure function, an "as left" test must be performed on the penetration to ensure leakage rates are acceptable.

The corrective actions taken as part of the Containment Leakage Rate Testing Program will ensure that the containment isolation check valves and MOVs remain capable of performing their containment pressure boundary integrity function under all CLB conditions.

CCNPP Pump and Valve IST Program

The leak rate testing of the check valves providing SR-NSR pressure boundary portions of the system is performed by Surveillance Test Procedures M-583-1 and M-583-2 as part of the overall CCNPP Pump and Valve IST Program. The Pump and Valve IST Program was established to implement IST in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, as required by 10 CFR 50.55a(f). American Society of Mechanical Engineers XI, Subsection IWV, directs each licensee to comply with the applicable portions of ASME/ANSI OM-10. American Society of Mechanical Engineers/ANSI OM-10 provides the rules and requirements for IST of CCNPP valves, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. In addition to the general Code requirements discussed above, there are additional interpretations and positions that have come about as a result of past regulatory and licensee actions, including NUREG-1482, Guidelines for Inservice Testing at Nuclear Power Plants. [References 29, 32, 33, 34, and 35]

Testing is implemented by CCNPP Technical Specification 4.0.5. The subject Group 1 check valves were voluntarily added to the IST program as part of the Augmented Testing Program for Non-Code Class Pumps and Valves, and are tested in accordance with ASME/ANSI OM-1987, including Oma-1988 Addenda. The subject check valves are required to be verified shut after a full-stroke closure every refueling outage in accordance with the Pump and Valve IST Program Third Ten-Year Interval. This verification is accomplished through leakage tests performed by Surveillance Test Procedures M-583-1 and M-583-2. [References 29 and 35]

Per References 33 and 34, the test includes the following procedural steps:

- Leak rate monitoring test equipment is connected to the appropriate test point.
- The upstream side is slowly depressurized to seat the valve. If slow depressurization does not seat the valve, then rapid depressurization is used.
- The leak rate is measured and recorded.
- The measured leak rate is compared against acceptance criteria for the valve.
- If measured leakage is less than or equal to the acceptance criteria the valve is satisfactory. If not, the System Engineer reviews the data and determines if corrective actions are required in accordance with the CCNPP Corrective Action Program.
- The "as left" measured leakage for the subject valve is added to the "as left" measured leakage for the other Compressed Air System valves tested in this procedure. The total leakage is compared against the maximum allowable leakage for the system.

- If the total leakage exceeds the maximum allowable leakage, the System Engineer is notified. The System Engineer determines if corrective action is required in accordance with the CCNPP Corrective Action Program.

The test procedure requires a comparison of measured valve leakage against permissible leakage rates for individual valves, based on valve size, as specified in ASME Section IWV-3426(b). This leakage criteria was also used as the assumed leakage when determining the maximum load on the SR air compressors. The test procedure also requires a comparison of total measured system leakage against the maximum allowable leakage rate. The maximum allowable leakage rate is established by Design Engineering. [References 33 and 34]

The corrective actions taken as part of the Pump and Valve IST Program will ensure that the check valve providing SR-NSR pressure boundary for the containment air portion of the system will remain capable of performing the system pressure boundary integrity function under all CLB conditions.

Group 1 (wear for check valves and MOVs) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to wear of check valves and MOVs for the Compressed Air System.

- The check valve disks/seats and MOV internals maintain containment pressure boundary or system SR-NSR pressure boundary and their integrity must be maintained under all CLB conditions.
- Wear is plausible for check valve disks/seats and MOV internals and results in material loss which, if left unmanaged, could eventually lead to leakage and loss of pressure boundary.
- The containment isolation valves are subject to local leak rate testing in accordance with the CCNPP Containment Leakage Rate Program.
- The check valves providing a SR-NSR pressure boundary function are subject to leak rate testing in accordance with the CCNPP Pump and Valve IST Program.
- Leak testing will continue to be performed by these programs in accordance with the plant Technical Specifications, and appropriate corrective actions will be taken if significant wear is discovered.

Therefore, there is reasonable assurance that the effects of wear for Compressed Air System check valves and MOVs will be managed in such a way as to maintain the components' pressure boundary integrity, consistent with the CLB, during the period of extended operation.

Group 2 (general corrosion for all device types except pumps) - Materials and Environment

General corrosion is considered plausible for components in the Compressed Air System that are constructed of carbon steel because of the potential exposure to slightly moist air. The Compressed Air System piping was evaluated for general corrosion as a whole because the entire sections of pipe, including fittings, flanges, and bolting, have the pressure boundary function and they are generally made of carbon steel. Piping above two inches is Schedule 40 carbon steel with buttwelded fittings. Piping two inches and below is Schedule 80 carbon steel with socket-welded fittings. Threaded connections are allowed on certain portions of the piping by the design specification. [Reference 4, Attachment 6; Reference 17]

The Group 2 device types were evaluated for general corrosion on a subcomponent basis. Each subcomponent was evaluated to determine whether it was required to maintain the pressure boundary of the system and was, therefore, subject to AMR. The materials of construction for each of the subcomponents subject to AMR were then evaluated. General corrosion is considered plausible for only those pressure retaining subcomponents which are constructed of carbon steel. Each device type has at least one subcomponent that is potentially susceptible to general corrosion. [Reference 4, Attachment 4s and Attachment 6s]

The internal environment for the Compressed Air System components is normally air supplied by the IA compressors. The air quality is discussed in Materials and Environment for Group 1.

Group 2 (general corrosion for all device types except pumps) - Aging Mechanism Effects

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. General corrosion requires an aggressive environment and materials susceptible to that environment. Carbon steels are subject to corrosion, i.e., rusting, due to exposure to water and the presence of oxygen. General corrosion is not plausible for Compressed Air System subcomponents constructed of alloy steel, stainless steel, brass, or aluminum because these materials are resistant to general corrosion in their operating environments. [Reference 4, Attachment 7s]

The ARDM is plausible in the Compressed Air System because the carbon steel materials of construction may occasionally be exposed to slightly moist air. The expected effects would be superficial rust speckles and a slight dusting of loose passive surface rust. The consequences of general corrosion damage to the affected component is a loss of load carrying cross-sectional area. However, general corrosion is not expected to reach the point where it affects the intended function of components in the Compressed Air System. [Reference 4, Attachment 6s and Attachment 8] An additional concern for the Compressed Air System results from the byproduct of corrosion, namely rust particles. Accumulation of rust particles around the diaphragm mechanism of the PCVs or the disk/seat of control valves and MOVs can contribute to wear. The wear aging mechanism is discussed above in Group 1.

Group 2 (general corrosion for all device types except pumps) - Methods to Manage Aging

Mitigation: The IA Subsystem air quality is normally maintained in accordance with industry standards for moisture (dewpoint) and particulate concentrations. Continued maintenance of IA Subsystem air quality to industry standards will ensure minimal component degradation resulting from moisture or from rust particles. The use of air dryers and filters maintains the air quality within acceptable limits. In order to assure that the compressed air quality remains within acceptable limits, the air quality should be periodically checked and compared against the industry standards. [Reference 4, Attachment 8] If testing shows a reduction in air quality, corrective actions can be initiated to return the air quality to normal.

The possibility of occasional exposure to slight moisture exists from operation of the saltwater air compressors because there is no dryer for this supply. The exposure to moisture is minimal and short term, and is not expected to result in significant levels of degradation of the carbon steel components. An inspection performed on the piping immediately downstream of the saltwater air compressors, where the worst case of general corrosion is expected, revealed only very light surface rust on the inside of each piece.

After more than 20 years in operation, approximately 60% of the pipe interior contained no rust and appeared similar to the inside of new pipe. Thickness measurements showed that the wall thickness averaged only 0.001 inch less than the nominal thickness of 0.179 inch. [Reference 4, Attachment 8] Since air in the IA and Saltwater Air Subsystems is normally very dry and there is so little corrosion evident after more than 20 years of operation, continued maintenance of the air quality is deemed an adequate aging management technique for general corrosion control in these subsystems.

Discovery: Although the PA Subsystem is designed to minimize the amount of particulates, moisture, and oil content in the air as described above in Materials and Environment, the PA Subsystem is not maintained to any specific air quality standards, and it does not contain any air dryers. Therefore, the carbon steel containment penetration components may be occasionally exposed to moist air. However, it is not expected to result in significant degradation or rapid attack of the carbon steel components because these lines are in use only during plant outages. Pressure testing for valve leakage would result in detection of minor degradation of the valve seating surfaces due to general corrosion. A visual inspection of the PA containment penetration piping and valves would assure that significant degradation is not occurring to the remaining internal surfaces of the piping and valves. [Reference 4, Attachment 8]

Group 2 (general corrosion for all device types except pumps) - Aging Management Program(s)

Mitigation:

CCNPP Preventive Maintenance Program

The CCNPP Preventive Maintenance Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. The program covers all preventive maintenance activities for nuclear power plant structures and equipment within the plant, including the Compressed Air System components within the scope of license renewal. [Reference 36] It is based on INPO documents, References 37, 38 and 39.

Calvert Cliffs initiated a Preventive Maintenance Task following a review of recommendations in Significant Operating Experience Report (SOER) 88-01. This task checks the IA Subsystem air quality at three locations in the system; at the dryer outlet, at the furthest point from the dryer, and at the approximate mid-point between the other two. Measurements of dew point and particulate count are taken every 12 weeks at these locations. This Preventive Maintenance Task is automatically scheduled and implemented in accordance with SR Preventive Maintenance Program procedures. [References 36 and 40]

According to procedure, dew point data and particulate sample results are provided to the System Engineer who is responsible for reviewing and evaluating the data in accordance with SOER 88-01. Significant Operating Experience Report 88-01 recommends maintaining the air quality within the requirements of standard ISA-S-7.3, “Quality Standard for Instrument Air.” Standard ISA-S7.3 recommends limits for maximum particle size, dew point temperature, and oil content. The System Engineer determines if the air quality is abnormal, and initiates corrective action to return the air quality to normal and to investigate the condition of the dependent load internals, as appropriate. [References 19 and 40]

The Preventive Maintenance Program has been evaluated by the NRC during Plant Performance Reviews which serve as inputs to the NRC Systematic Assessment of Licensee Performance and senior management meeting reviews. [Reference 41] The plant Maintenance Program itself has numerous levels of management review, all the way down to the specific implementation procedures. For example, the Principal Engineer - Reliability Engineering Unit and Principal Engineer - Maintenance/Component Engineering both have specific responsibilities for evaluating and upgrading the Preventive Maintenance Program. The System Engineer and System Manager have specific responsibilities for initiating changes to the Preventive Maintenance Program based on results of the tests. These controls provide reasonable assurance that the Preventive Maintenance Program will continue to be an effective method of mitigating the effects of general corrosion on the Compressed Air System components. [Reference 36]

Operating experience relative to air quality control of the IA Subsystem has shown that the air normally provided is very dry and contains little particulate matter. The air is supplied by oil-free compressors. Dewpoint results are typically less than -40ºF at 100 psig, which is well below the requirement; i.e., at least 18ºF below the minimum local recorded ambient temperature at the plant site. Particulate sampling shows a relatively normal distribution of particle sizes for a filtered Compressed Air System. The little amount of particulate measured which exceed specific component maximum particulate requirements is captured in local filters at those components. No trace of oil or hydrocarbons has been detected, so oil content is no longer routinely monitored. The normal supply of air is from the IA compressors which are of oil-free design. [Reference 23]

Discovery: Continued implementation of the mitigation technique discussed above should ensure that exposure of the IA Subsystem carbon steel components to moisture will continue to be minimal. Since the Saltwater Air Subsystem is only installed as a backup to the IA Subsystem essential loads, introduction of moisture from this subsystem will also be minimal. Corrosion of these components is not expected to result in significant levels of degradation. It is deemed that the mitigation techniques described above are adequate aging management practices for general corrosion, and no discovery techniques are necessary for the IA and Saltwater Air Subsystems.

Since the PA Subsystem is not maintained to any specific air quality standards, the carbon steel containment penetration components may be occasionally exposed to moist air. The containment penetration portion of the PA Subsystem will therefore be included in a new program to accomplish the needed inspections for general corrosion. The new program will be considered an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0 of the BGE LRA.

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of the inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of unacceptable examination findings, including consideration of all design loadings required by the current licensing basis (CLB), and specification of required corrective actions; and

- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

In addition to the ARDI Program, the PA Subsystem containment isolation valves will be subject to periodic testing. These valves are subject to local leak rate testing under the Surveillance Test Procedures M-571F-1 and M-571F-2 in accordance with 10 CFR Part 50 Appendix J. [Reference 4, Attachment 8; References 26, 27, and 28, Section 1.0] Pressure testing for valve leakage will result in detection of minor degradation of the valves' seating surfaces due to corrosion. Continued local leak rate testing on a periodic basis will assure acceptable leak tightness of these valves and will also ensure that any leakage remains within the guidelines of the Technical Specifications.

The LLRT is part of the overall CCNPP Containment Leakage Rate Testing Program. This program is discussed in detail above for Group 1. The corrective actions taken as part of the Containment Leakage Rate Testing Program and ARDI Program will ensure that the containment isolation portion of the PA Subsystem remains capable of performing the containment pressure boundary integrity function under all CLB conditions.

Group 2 (general corrosion for all device types except pumps) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to general corrosion of Compressed Air System components:

- The Compressed Air System components provide the system pressure-retaining boundary and their integrity must be maintained under CLB design conditions.
- General corrosion is plausible for the carbon steel components and results in material loss which, if left unmanaged, can lead to loss of pressure-retaining boundary integrity.
- The rate of attack is affected by the amount of moisture in the air because the moisture could condense on Compressed Air System carbon steel components.
- The dew point temperature, which is indicative of air moisture content, is maintained low in the IA Subsystem and is periodically measured and tracked in accordance with the Preventive Maintenance Program. If the air quality becomes abnormal, corrective actions are initiated to return the air quality to normal and to investigate the condition of the dependent load internals, as appropriate.
- Since the PA Subsystem is not maintained to any specific air quality standards, the containment isolation portion of this subsystem will be included in the scope of an ARDI Program. Inspections will be performed and appropriate corrective action will be taken if significant corrosion is discovered.
- To provide assurance that general corrosion of valve seating surfaces is not threatening the containment boundary for the PA Subsystem, this portion will also be periodically leak tested in accordance with the Containment Leakage Rate Testing Program. The Containment Leakage Rate Testing Program includes requirements for corrective actions if the leak rates become unacceptable.

Therefore, there is reasonable assurance that the effects of general corrosion on Compressed Air System components will be managed in such a way as to maintain the components' pressure boundary integrity, consistent with the CLB, during the period of extended operation.

5.4.3 Conclusion

The programs discussed for the Compressed Air System are listed in Table 5.4-3. These programs are (and will be for new programs) administratively controlled by a formal review and approval process. As has been demonstrated in the above section, these programs will manage the aging mechanisms and their effects such that the intended functions of the components of the Compressed Air System will be maintained, consistent with the CLB, during the period of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

Table 5.4-3
LIST OF AGING MANAGEMENT PROGRAMS FOR THE COMPRESSED AIR SYSTEM

	Program	Credited As
Existing	CCNPP Pump and Valve IST Program Surveillance Test Procedures M-583-1 and M-583-2	• Discovery and management of the effects of seating surface wear of the check valves that provide SR-NSR pressure boundary for portions of the Compressed Air System (Group 1)
Existing	CCNPP Local Leak Rate Test Program: Unit 1 Procedure STP-M-571F-1, "Local Leak Rate Test, Penetrations 19A (Inst Service) 19B (Service Air)" Unit 2 Procedure STP-M-571F-2, "Local Leak Rate Test, Penetrations 19A (IA), 19B (PA)"	• Discovery and management of leakage that could be the result of seating surface wear of the check valves and MOVs that provide IA Subsystem containment pressure boundary (Group 1) • Discovery and management of leakage that could be the result of general corrosion of the valves' seating surfaces that provide PA Subsystem containment pressure boundary (Group 2)
Existing	CCNPP Maintenance Program Procedure MN-1-102, "Preventive Maintenance Program" Preventive Maintenance Repetitive Tasks 10191024 and 20191022	• Mitigation of the effects of general corrosion of the Compressed Air System carbon steel components (Group 2)
New	ARDI Program	• Discovery and management of the effects of general corrosion of the containment penetration portion of the PA Subsystem carbon steel components (Group 2)

5.4.4 References

1. "CCNPP Updated Final Safety Analysis Report," Revision 20
2. CCNPP Drawing No. 61082SH0004, "Schematic Diagram Plant and Instrument Air Control Valves 1-CV-2059 and 1-CV-2061," Revision 6, January 3, 1989
3. CCNPP Drawing No. 63082SH0004, "Schematic Diagram Plant and Instrument Air Control Valves 2-CV-2059 and 2-CV-2061," Revision 7, December 5, 1988
4. "CCNPP Compressed Air System AMR Report," Revision 4, June 25, 1997
5. CCNPP Drawing No. 60712SH0001, "Compressed Air System, Instrument Air and Plant Air," Revision 46, December 5, 1996
6. CCNPP Drawing No. 60712SH0003, "Compressed Air System, Instrument Air and Plant Air," Revision 75, August 2, 1996
7. CCNPP Drawing No. 60712SH0005, "Compressed Air System, Instrument Air and Plant Air," Revision 46, November 11, 1996
8. CCNPP Drawing No. 62712SH0001, "Compressed Air System, Instrument Air and Plant Air," Revision 37, July 24, 1996
9. CCNPP Drawing No. 62712SH0003, "Compressed Air System, Instrument Air and Plant Air," Revision 80, February 19, 1997
10. CCNPP Drawing No. 60746SH0002, "Plant Water and Air System Service," Revision 23, November 1, 1996
11. CCNPP Drawing No. 61076SH0046, "Schematic Diagram Reactor Safeguards Saltwater System Air Compressors 11 and 12," Revision 9, August 12, 1993
12. "Component Level Screening Results for the Compressed Air System, System No. 019, CCNPP," Revision 3, December 20, 1996
13. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 4, August 27, 1996
14. "CCNPP Fire Protection AMR Report," Revision 1, January 29, 1997
15. CCNPP Drawing No. 63076SH0046, "Schematic Diagram Reactor Safeguards Saltwater System Air Compressors 11 and 12," Revision 7, December 13, 1993
16. CCNPP Drawing No. 92769SH-HB-4, "M-601 Piping Class Summary," Revision 23, July 31, 1996
17. CCNPP Drawing No. 92767SH-HB-1, "M-600 Piping Class Sheets," Revision 57, July 31, 1996
18. Letter from Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated February 17, 1989, "Response to NRC Generic Letter 88-14, Instrument Air Supply Problems Affecting Safety-Related Equipment"
19. INPO SOER 88-01, "Instrument Air System Failures," May 18, 1988

20. NRC Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," August 8, 1988

21. Letter from Mr. D. G. McDonald, Jr. (NRC) to Mr. G. C. Creel (BGE), dated April 18, 1990, "Response to Generic Letter 88-14, Instrument Air Supply System Problems Affecting Safety Related Systems - Calvert Cliffs Nuclear Power Plant, Units 1 and 2"

22. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, Licensee Event Report 89-018-01, "Failure of SR Air Accumulators to Perform as Required Results in a Condition that Could Have Prevented Certain Systems from Performing Their Intended Safety Functions," April 6, 1990

23. Letter from Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated May 25, 1989, "Response to Request for Additional Information Generic Letter 88-14, Instrument Air Supply System Problems Affecting Safety-Related Equipment"

24. CCNPP "Pre-Evaluation Results for the Compressed Air System (#019)," Revision 6, November 30, 1995

25. CCNPP Operations Performance Evaluation Requirement Nos. 1-12-3-O-M and 2-12-3-O-M, "Run Saltwater Air Compressors," Revision 2, February 4, 1997

26. Letter from Mr. A. W. Dromerick (NRC) to Mr. C. H. Cruse (BGE), "Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit 1(TAC No. M92549) and Unit 2 (TAC No. M92550)," dated October 18, 1996 [Amendment Nos. 217/194]

27. CCNPP Surveillance Test Procedure STP-M-571F-1, "Local Leak Rate Test, Penetrations 19A (Inst Service), 19B (Service Air)" (Unit 1), Revision 0, May 17, 1991

28. CCNPP Surveillance Test Procedure STP-M-571F-2, "Local Leak Rate Test, Penetrations 19A (Instrument Air), 19B (Plant Air)" (Unit 2), Revision 0, October 17, 1991

29. CCNPP Administrative Procedure EN-4-102, "ASME Pump and Valve Testing," Revision 1, September 18, 1996

30. 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors"

31. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated January 16, 1996, "License Amendment Request: Adoption of 10 CFR Part 50, Appendix J, Option B for Type A Testing"

32. CCNPP Administrative Procedure EN-4-104, "Surveillance Testing," Revision 1, October 23, 1996

33. CCNPP Technical Procedure Unit 1 STP M-583-1, "Instrument Air Safety Related Pressure Boundary Check Valve Leak Test," Revision 0, April 4, 1996

34. CCNPP Technical Procedure Unit 2 STP M-583-2, "Instrument Air Safety Related Pressure Boundary Check Valve Leak Test," Revision 0, April 4, 1996

35. "CCNPP Pump and Valve Inservice Testing Program Third Ten-Year Interval," April 30, 1997

36. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996

37. INPO 85-032, "Preventive Maintenance," December 1988

38. INPO 85-037, "Reliable Power Station Operation," October 1985

39. INPO Good Practice MA-319, "Preventive Maintenance Program Enhancement," December 1992

40. Repetitive Tasks 10191024 and 20191022, "Check Instrument Air Quality at System Low Points," Preventative Maintenance Program

41. Letter from Mr. R. W. Cooper, II (NRC) to Mr. C. H. Cruse (BGE), dated May 31, 1996, "Calvert Cliff's Plant Performance Review Results"